CANADIAN PETROLEUM ASSOCIATION

Submission
To The
Royal Commission
On Energy

Exhibit no. C-11-1

CANADIAN PETROLEUM ASSOCIATION

SUBMISSION

TO THE

ROYAL COMMISSION ON ENERGY

7th February, 1958 :

February 7th, 1958.

The Royal Commission on Canada's Energy Resources.

Gentlemen :

By order of the Board of Governors of the Canadian Petroleum Association, I submit herewith the Association's studies on subjects of concern to your Commission as listed in the table of contents.

The purpose of this submission is to acquaint the members of the Commission with the problems facing the exploration and production phases of the Oil and Gas Industry in Canada.

In order to assist the Commission, additional statistical information regarding marketing and refining facilities have been included in this submission.

Respectfully yours,

John W. Proctor

John W. Proctor
General Manager:

For and On Behalf of The Canadian Petroleum Association.

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Introduction

The Canadian Petroleum Association is an association of some 274 Exploration and Producing Companies which together produce 97% of the Oil and Gas produced in Canada. The Association also has 63 Associated member companies whose business is ancillary to the search for and production of oil and gas.

The principal purposes of the Association are:

(i) To establish better understanding between the petroleum and natural gas industry and the public;

(ii) To encourage cooperation between the petroleum and natural gas industry and Federal, Provincial and local governments, and other authoritative bodies;

(iii) To provide a forum for the discussion of matters affecting the welfare of its members;

(iv) To foster better understanding between this Association and other organizations with similar objects and purposes.

The Association is governed by a Board of Governors elected annually by secret ballots. Each company regardless of its financial structure or the extent of its activities, has only one vote.

The Association is further sub-divided into:

(1) Alberta Division with its own Board of Directors.

(2) Saskatchewan Division with its own Board of Directors.

(3) A Standing Committee for British Columbia.

(4) A Standing Committee for Manitoba.

(5) A Standing Committee for The Northwest Territories.

(6) 60 Standing Committees dealing with Industry Problems.

The Board of Governors is responsible for co-ordinating policy among the divisions and committees and for overall Canadian Policy. The constitution of the Association allows for the establishment of further Divisions as the industry expands in other parts of Canada.

As a service to its members the Association maintains a Statistical Department, and periodically issues industry statistics of interest to its members and to Governmental and Regulatory Bodies. Among these Statistics are estimates of reserves of oil and gas compiled from data furnished by member companies.

Owing to the highly competitive nature of the oil and gas business the members regard their estimates of reserves as confidential records and give them to the Canadian Petroleum Association only on the understanding that they will be held in the strictest confidence. Without this understanding no information would be given, and the C.P.A. would be unable to compile accurate records.

Reserve estimates are compiled by areas in such a manner that no member of the Reserves Committee knows what the total reserves of any individual company are, but only knows its reserves in the particular area to which he has been assigned.

The following information and data deals only with the industry as a whole. For the purposes of this brief in matters and problems of the industry of a controversial nature where the Association cannot represent the policy of all its members, no recommendations are made,

as the Association cannot show partiality towards any one group.

Therefore, in preparation of this Brief, the Association has been able to deal only with the subjects on which there is no apparent conflict of opinion or interests among its members.

PRESENT PROVINCIAL POLICY TOWARDS EXPLORATION, DEVELOPMENT, DRILLING, CONSERVATION AND PRODUCTION.

The policies of all four western provincial governments are sufficiently similar that they can be commented upon collectively, the comments upon one, generally speaking, being applicable to all four.

Broadly speaking, provincial government regards the petroleum industry as a partner in the industrial progress of the province. Its policy is to encourage development of its mineral resources by private enterprise and obtain a just land owner's revenue for the people of the province at no financial risk. Rights to explore and produce are sold and leased on terms sufficiently stringent to yield a handsome return to the provincial treasury (In Alberta some $700 million in the past eleven years) and sufficiently lenient to have attracted an influx of risk capital in excess of $3 billion. Stability of Government and a declared intention not to enter the oil business in competition with industry, have also been considerable factors in attracting risk capital.

Regulations in force are aimed largely at maintaining equity among all producers large and small, ensuring efficient operation and the prevention of waste or over production and encouraging active exploration. While strictly enforced they are generally not so onerous that industry can not live with them agreeably.

However, Governmental Authorities maintain a rigid control upon its mineral resources, by means of permits, licences, etc. and virtually no operation can be undertaken without government consent. This is particularly true in the matters of export of natural gas.

For example. For some years, the Province of Alberta would not allow any natural gas to be exported from the province. When it was proved conclusively that the gas resources were far in excess of the provinces needs in the forseeable future, it permitted export of the surplus. Estimates of reserves and provincial requirements are revised each year, and only the surplus is considered available for export permit.

A co-operative atmosphere exists between industry and Provincial Government at all levels. Round table conferences to discuss problems which arise are of fairly common occurrence and are mutually beneficial.

INVESTMENT AND ECONOMICS

Statistical data on expenditures and income of oil and gas producers in Western Canada have been compiled and analyzed for the period 1951-56. This period was chosen because published records of industry expenditures are not available for prior years. However, we feel that this period taken as a whole, gives a realistic insight into the unusual economics of oil and gas exploration and production.

Investment in Crude oil and Natural Gas Reserves 1951-56.

Acquisition costs (land acquisition and rentals, geological and geophysical, exploratory drilling) are the largest expenditures of the industry and a major portion of them resulted in neither oil nor gas production. In many cases, although resulting in production, the potential income developed is less than the amount invested in the prospect.

Almost all expenditures under "acquisition costs" were directed primarily towards exploration for oil. Results indicate a favorable discovery rate for natural gas, but in very few instances was exploration directed towards its discovery. The extremely long delay between investment and income, resulting in a lengthy payout, minimizes the incentive to explore for natural gas. The rate of return on investment fluctuates with the length of the payout period. Restricted crude oil production -- as it prevails to a large degree at the present time -- will lengthen the payout and thus reduce the rate of return on investment. If this situation should prevail for a prolonged period, it will have the same effect on exploration for oil as it has shown on exploration for gas.

Development costs are mostly the charges for the completion of wells to make possible the withdrawal of the reserves discovered. It must

be realized, when considering these expenditures, that natural gas reserves have only been developed to a very limited extent. In future years, vast sums of capital will be required for development wells, field equipment, and processing plants before revenue can be derived. Investment statistics for 1957 are not available but they will, to some degree, reflect higher development expenditures as producers commenced the development of gas discoveries to meet the requirements of the Trans-Canada and Westcoast Transmission pipe lines.

Wildcat drilling records for British Columbia and the Prairie Provinces show that, from 1951 to 1956, the 3,722 wildcat tests drilled, found 67 commercial oil and 134 commercial gas fields, or 1 oil to 2 gas, (commercial being defined as the discovery of reserves of more than one million barrels of oil or 10 billion cubic feet of gas). In the same period, development statistics show only one gas well completed for every 19 oil wells.

Income from Production 1951 - 1956.

Oil and gas produced during this period brought in $1,453 million. From this must be deducted a royalty share for the holder of the mineral rights and the operating costs associated with the withdrawal of the reserves.

Industry Cash Position 1951 - 56

During the period 1951 - 56, the industry invested $1.89 in exploration and development of reserves for every dollar of operating income, thus incurring a cash deficit of $936 million. The deficit is still increasing after more than 10 years of success ful operations.

The extensive investment of $1,991 million has been made with the belief that the reserves found - both oil and gas - could be produced and

sold with a reasonable dispatch. The strength of the industry and future expansion depend directly on the prospects for the recovery of not only the present cash deficit, but also the recovery of new investment, in a reasonable period of time. The investment climate must be kept sufficiently appealing to foster re-investment and to attract new risk capital.

ESTIMATED INVESTMENT AND INCOME 1951 - 1956

INVESTMENT:		
Acquisition Cost		
Land Acquisition & Rentals	$483,100,000	
Geological and Geophysical	$398,800,000	
Exploratory Drilling	$421,500,000	
	$1,303,400,000	
Development Cost	$687,300,000	
TOTAL INVESTMENT		$1,990,700,000
INCOME		
Value of Production		
Crude Oil	$1,403,600,000	
Natural Gas	49,000,000	
	$1,452,600,000	
Less Royalty Payments(at 12.5%)	181,600,000	
Less Production Expenditures	$ 216,100,000	
Income from Production		$1,054,900,000
NET CASH DEFICIT		$ 935,800,000

Long Term Investment Analysis

Through the future sale of the oil and gas reserves discovered in the period 1951 - 56, producers look forward to an eventual profit. To illustrate this, a summary of costs on a "per barrel basis" has been prepared.

For simplification a constant production life of 20 years was assumed. Normally large fields produce over a longer period, and delays between exploration, discovery, development and production must be included when considering interest charges.

At present, there are over 700 gas wells in Alberta which have never been produced, representing an investment of over $ 60 million in well costs alone. Some of these wells were drilled as early as in the 1930's. The risk capital ventured in their drilling has not as yet produced any return and the cost of carrying these unproductive investments appreciates rapidly throughout the years.

Reserves to the petroleum and natural gas producer are comparable to the inventories of raw material which other industries require. However, only in the natural resources industries

1) are such vast volumes evicent, and
2) is interest on investment, therefore, such a major item.

The oil and gas industry by its very nature requires that these inventories be paid for in advance. Thus, in an investment analysis, the interest that could otherwise be earned on the money invested in finding and developing these reserves, must be considered. It should be noted that the analysis

1) does not consider taxes, and
2) assumes immediate sale of all gas discovered during the period 1951 - 56

When the production of either oil or gas is extensively delayed and/or considerably below the market that the reserves are capable of serving, the economic future of the industry is substantially depressed. Under current conditions of decreased revenue and high cost of carrying investment, prospects for improvement in the marketing picture are a prerequisite to a continued high level of activity in Western Canada's oil and gas exploration.

INVESTMENT ANALYSIS

	BBLS.	TOTAL $	$/BBL
RESERVES:			
Crude Oil	2,194,400,000	---	---
Natural Gas(Equiv. bbls) (1)	390,000,000	---	---
	2,584,400,000		
INVESTMENT			
Acquisition cost	----	1,303,400,000	0.50
Development Cost (2)	----	687,300,000	0.31
Carrying Charge on(3) Investment (at 6%)	----	1,480,500,000	0.61
ROYALTY PAYMENTS(at 12.5%)	--	181,600,000	0.30
OPERATION OF WELLS(4)	603,600,000	216,100,000	0.36
TOTAL EXPENDITURES	----	----	2.08
GROSS INCOME FROM OIL & GAS PRODUCED.	----	----	2.41

(1) For the purposes of illustration, natural gas was converted to crude oil on the basis 30 MCF = 1 BBL

(2) Development costs have been calculated against crude oil reserves only.

(3) The interest which would have been earned at 6%, on the investment in exploration and development, assuming equal annual repayments over twenty years.

(4) As experienced during the period 1951-56. In future years, as decline sets in, per well production will decrease resulting in higher per barrel cost. Also generally operation of wells will be more costly due to maintenance factors. In the U.S. the average cost per barrel for fields in all stages of depletion was reported to be 65 cents in 1953(Petroleum Engineer, July 1955).

INVESTMENT ANALYSIS

In the following analysis, the presentation has been simplified by assuming that reserves are withdrawn at a constant rate over 20 years. This is not the case, since the average field produces throughout its early life at a constant rate and then declines over the remaining years, often extending beyond 20 years.

This analysis was designed to illustrate the effect of delayed income on the profitability of investment in exploration and development. The rate of return is dependent upon the initial rate of withdrawal and the decline assumed.

Production of Reserves Found 1951 - 1956

	Barrels	Dollars	$/Barrel
Reserves			
Crude Oil (1)	2,194,400,000		
Natural Gas(equivalent bbls)	390,000,000		
	2,584,400,000		
Income from Production			
Gross Revenue at 2.41		6,228,400,000	2.41
Royalty Payments at 12½%		-778,550,000	-0.30
Production Cost(2)		-930,380,000	-0.36
		4,519,470,000	1.75
Investment			
Acquisition		1,303,400,000	0.50
Development (3)		687,300,000	0.31
		1,990,700,000	0.81
Return on Investment before taxes			9%

(1) For purpose of this illustration, natural gas was converted to crude oil on the basis of 30 MCF ≒ 1 bbls.

(2) As experienced during the period 1951-56. In future years, as decline sets in, per well production will decrease resulting in higher per barrel cost. Also generally operation of wells will be more costly due to the maintenance factors. In the U.S. the average cost per barrel for fields in all stages of depletion was reported to be 65 cents in 1953 (Petroleum Engineer, July, 1955).

(3) Development costs per barrel have been calculated against crude oil reserves only.

ESTIMATED EXPENDITURES
1951 - 1956 (1)
(Thousand dollars)

	Alberta	B. C.	Sask.	Man.	Total
Acquisition Costs					
Land Acquisition & Rentals	392,500	3,800	64,800	22,000	483,100
Geological & Geophysical	323,300	24,000	45,100	6,400	398,800
Exploration Drilling	314,000	26,900	67,400	13,200	421,500
	1,029,800	54,700	177,300	41,600	1,303,400
Development Costs	540,400	2,900	112,900	31,100	687,300
Operation of Wells	195,700	100	15,700	4,600	216,100
TOTAL	1,765,900	57,700	305,900	77,300	2,206,800

(1) Estimated using as sources, expenditures published by the Provincial Governments of Alberta, Saskatchewan and British Columbia. Manitoba has been estimated on the basis of wells drilled, geophysical activity and a land survey.

Production costs for other provinces are estimated to be the same as Alberta.

The Northwest Territories were omitted.

OIL AND GAS RESERVES IN CANADA

The proved oil and gas reserves as defined according to the modified rules of the American Petroleum Institute and the American Gas Association, and the probable oil and gas reserves, have been estimated for Canada. The possible oil and gas reserves have been estimated quantitatively only for the Western Canada interior basin, although other basins are briefly described herein.

Estimated Crude Oil and Natural Gas Liquid Reserves as of December 31, 1957.

	Proved	Add'n Probable
	(thousands of barrels)	
Northwest Territories	52,858	58,500
British Columbia	25,602	44,153
Alberta	2,721,587	816,771
Saskatchewan	420,954	172,074
Manitoba	34,258	5,065
Total Western Canada	3,255,259	1,096,563
Ontario	3,763	-
New Brunswick	92	
Total Eastern Canada	3,855	-
TOTAL CANADA	3,259,114	1,096,563

Offprt 100% wld be marketable

Estimated Producible Natural Gas Reserves as of December 31, 1957.

	Proved	Add'nal Probable
	(MMCF)	
Northwest Territories	29,705	30,274
British Columbia	1,803,075	662,216
Alberta	17,702,885	8,927,289
Saskatchewan	1,011,118	48,524
Manitoba	2,993	467
Total Western Canada	20,549,776	9,668,770
Ontario	190,287	-
Quebec	983	-
New Brunswick	1,085	-
Total Eastern Canada	192,355	-
TOTAL CANADA	20,742,131	9,668,770

Offprot 91% wld be marketable

PROVED AND PROBABLE OIL, NATURAL GAS AND NATURAL GAS LIQUID RESERVES

PROVED RESERVES

In calculating proved reserves of oil, natural gas, and natural gas liquids, the Canadian Petroleum Association Reserves Committee follows closely the principles established by the American Petroleum Institute's Committee on Petroleum Reserves, and the Committee on Natural Gas Reserves of the American Gas Association. Copies of the Rules for calculating such reserves are attached as Appendix I .

It will be noted from these Rules that proved reserves are both drilled and undrilled. The proved undrilled reserves in any pool include reserves under undrilled spacing units which are so related to the drilled units that there is every reasonable expectation that they will produce when drilled. As a general rule in partially developed fields, only lateral and diagonal offsets to drilled wells are included. However, where the geological information is such that there is every reasonable expectation that undrilled spacing units further removed will produce when drilled, such spacing units are included.

In the case of new discoveries, both of new fields and of new pools in old fields, in which there is only one well drilled at the time of making the estimate, it is the practice to use only one spacing unit for reserve calculations except where sufficient information is available to warrant taking in a larger area.

In a pool in which wells have been drilled, cased and found

uncommercial after production tests, no reserves are estimated.

Reserves which become available as a result of fluid injection are regarded as proved only after a thorough test by a pilot project, or after operation of an installed fluid injection procedure has actually demonstrated certainty of increased recovery.

Estimates of proved recoverable natural gas reserves are those calculated to be producible down to an abandonment pressure considered practicable.

Reserves of natural gas liquids in respect to an oil field are included only when there is a plant in operation for the recovery of the liquids. In the case of a wet gas field, or a substantial gas cap overlying an oil column, reserves of natural gas liquids are included in the estimates whether or not there is a plant in operation.

Experience has demonstrated that proved reserves calculated by these rules are less, overall, than ultimate recovery.

PROBABLE RESERVES

X Probable reserves of oil, natural gas and natural gas liquids were estimated for submission to this Commission. The additional reserves included in these estimates result from the following:

(1) Larger areal extent of proved fields, or the area assigned to discovery wells with relatively thick pay sections, which reasonably can be expected to produce on the basis of geological or geophysical information available.

(2) Additional reserves which may become available as a result of fluid injection. Included in this category are reserves from fields where pilot plants have actually indicated

the probability of additional recovery as a result of fluid injection, or where laboratory studies have indicated probable increases. In certain instances, increased recovery was only estimated for the area where plans have been formulated for fluid injection.

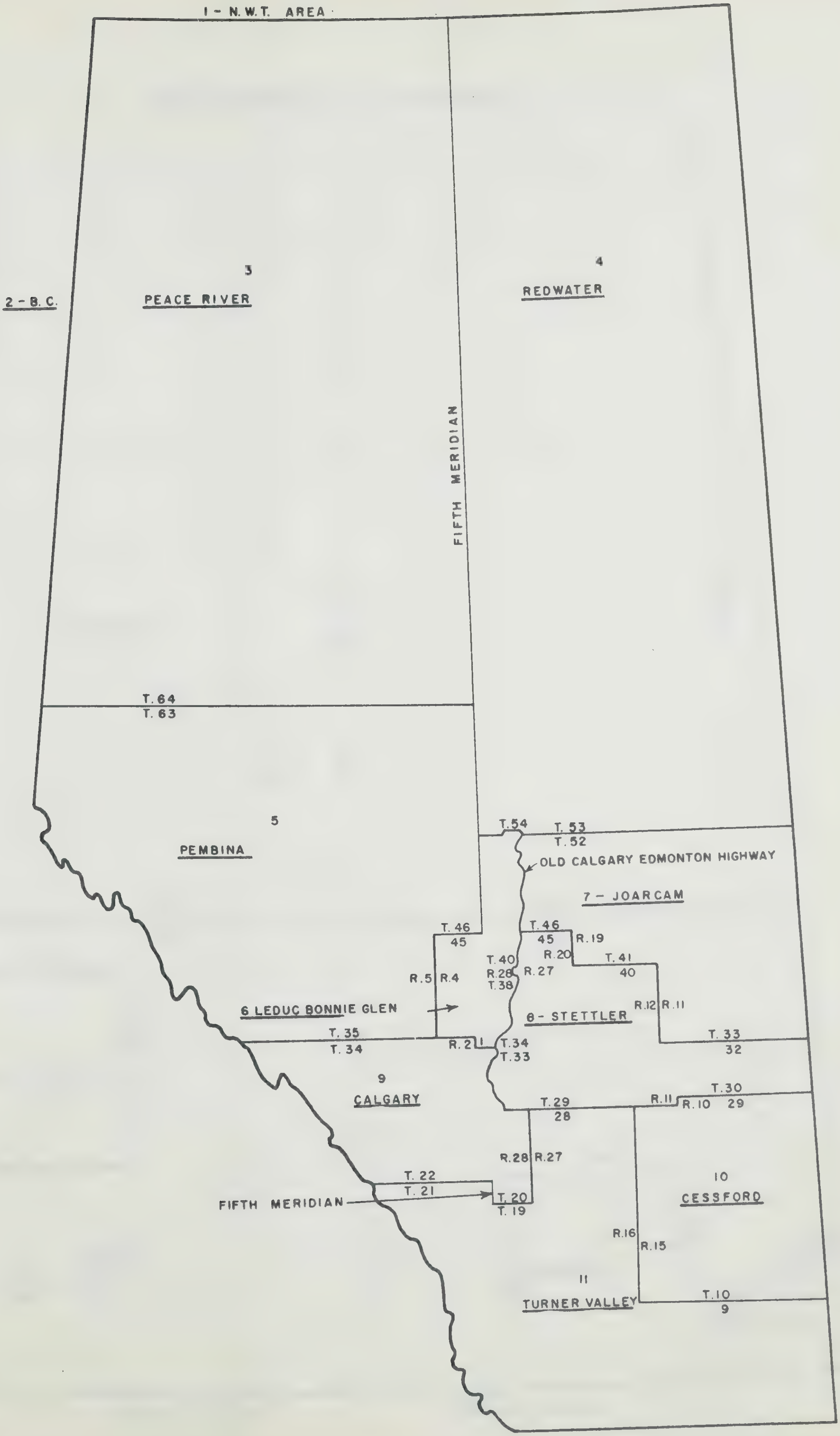
(3) Increased recovery from presently proved fields. The increased recovery is based on reservoir studies which indicate that more oil probably will be recovered, but such reserves cannot be considered in a proved category until substantiated by additional reservoir performance.

ESTIMATE OF PROVED AND PROBABLE RESERVES OF LIQUID HYDROCARBONS IN CANADA
(thousands of barrels)

	Crude Oil		Natural Gas Liquids	
	Remaining Proved Reserves as of Dec.31/57	Additonal Probable Reserves as of Dec.31/57	Remaining Proved Reserves as of Dec.31/57	Additional Probable Reserves as of Dec.31/57
Northwest Territories	52,858	58,500	-	-
British Columbia	2,093	35,525	23,509	8,628
Alberta				
Area 3	133,892	41,000	-	-
Area 4	544,430	72,415	10,006	-
Area 5	430,745	247,760	25,000	97,500
Area 6	850,734	19,288	180,880	8,546
Area 7	36,692	33,565	-	-
Area 8	252,229	56,847	28,563	-
Area 9	81,074	13,580	19,171	55,065
Area 10	2,705	5,000	-	-
Area 11	18,432	82,000	107,034	84,205
Total Alberta	2,350,933	571,455	370,654	245,316
Saskatchewan				
Area 1	11,393	2,640	-	-
Area 2	22,052	600	497	-
Area 3	56,560	13,351	-	-
Area 4	57,532	6,679	-	-
Area 5	142,288	111,000	-	20,404
Area 6	130,632	17,400	-	-
Total Saskatchewan	420,457	151,670	497	20,404
Manitoba	34,258	5,065	-	-
Eastern Canada				
Ontario	3,763	-	-	-
Quebec	-	-	-	-
New Brunswick	92	-	-	-
Total Eastern Canada	3,855	-	-	-
Total Canadian	2,864,454	822,215	394,660	274,348

ESTIMATE OF PROVED AND PROBABLE RESERVES OF NATURAL GAS IN CANADA
(MMCF)

	Remaining Proved Reserves as of Dec.31/57	Additional Probable Reserves as of Dec.31/57
Northwest Territories	29,705	30,274
British Columbia	1,803,075	662,216
Alberta		
Area 3	763,286	596,700
Area 4	844,778	789,553
Area 5	1,495,854	475,838
Area 6	3,508,261	729,473
Area 7	1,343,113	340,665
Area 8	1,595,288	497,550
Area 9	1,735,234	2,457,736
Area 10	2,326,801	900,000
Area 11	4,090,270	2,139,774
Total Alberta	17,702,885	8,927,289
Saskatchewan		
Area 1	20,692	1,785
Area 2	382,444	17,025
Area 3	206,171	94,464
Area 4	18,313	-
Area 5	357,095	- 68,050
Area 6	26,403	3,300
Total Saskatchewan	1,011,118	48,524
Manitoba	2,993	467
Eastern Canada		
Ontario	190,287	-
Quebec	983	-
New Brunswick	1,085	-
Total Eastern Canada	192,355	-
Total Canadian	20,742,131	9,668,770


1 - N.W.T. AREA
2 - B.C.
3
PEACE RIVER
4
REDWATER
FIFTH MERIDIAN
T. 64
T. 63
5
PEMBINA
T. 54
T. 53
T. 52
OLD CALGARY EDMONTON HIGHWAY
7 - JOARCAM
T. 46
45
T. 46
45
R. 19
R. 20
T. 41
40
T. 40
R. 28
T. 38
R. 27
R. 5
R. 4
6 LEDUC BONNIE GLEN
8 - STETTLER
R. 12
R. 11
T. 35
T. 34
R. 21
T. 34
T. 33
T. 33
32
9
CALGARY
T. 29
28
R. 11
R. 10
T. 30
29
R. 28
R. 27
T. 22
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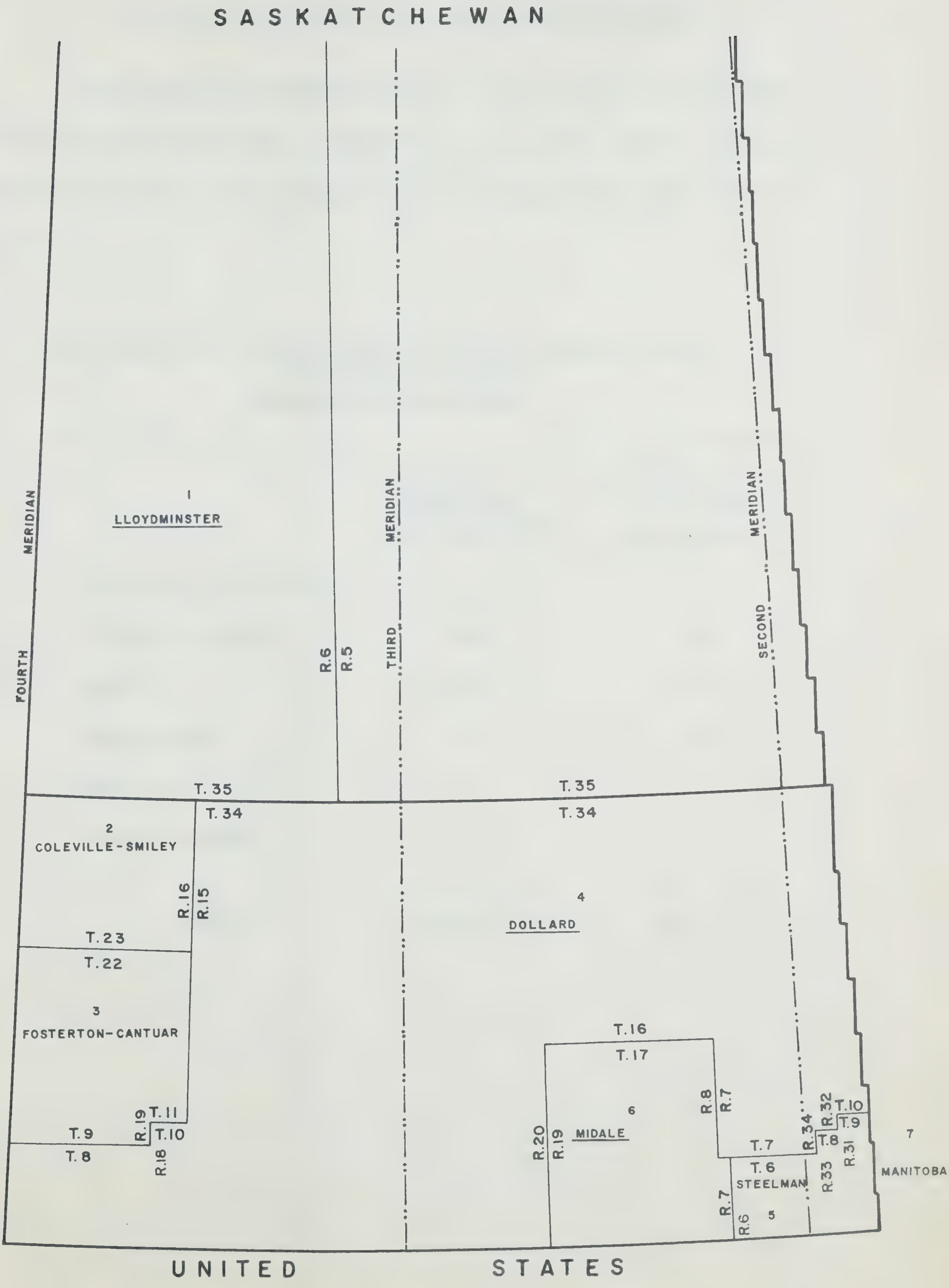
FIFTH MERIDIAN
T. 20
T. 19
10
CESSFORD
R. 16
R. 15
11
TURNER VALLEY
T. 10
9



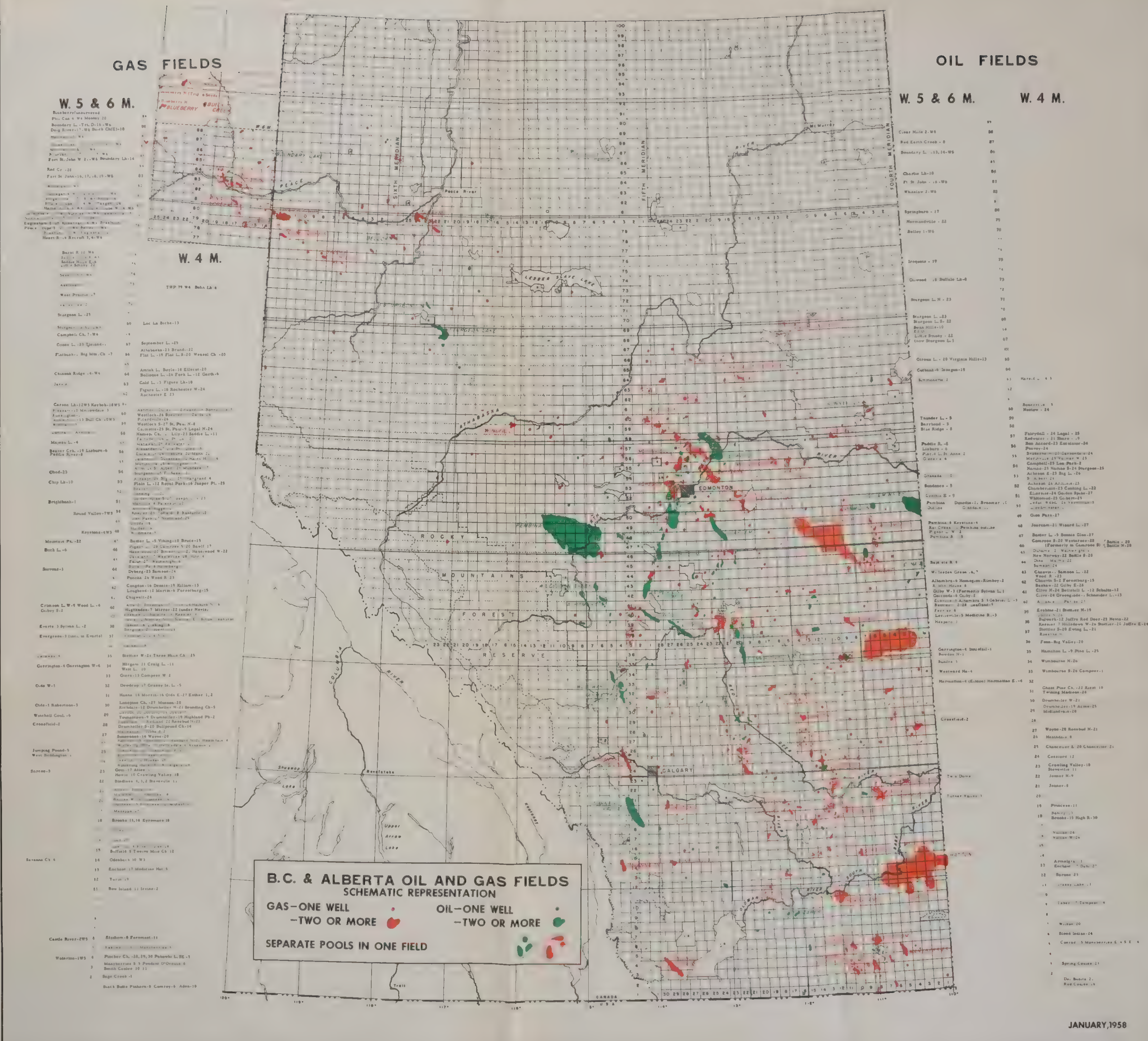
SASKATCHEWAN
FOURTH MERIDIAN
THIRD MERIDIAN
SECOND MERIDIAN
1
LLOYDMINSTER
R.6
R.5
T.35
T.34
T.35
T.34
2
COLEVILLE-SMILEY
R.16
R.15
T.23
T.22
3
FOSTERTON-CANTUAR
R.19
T.11
T.10
T.9
T.8
R.18
4
DOLLARD
T.16
T.17
6
MIDALE
R.20
R.19
R.8
R.7
T.7
T.6
STEELMAN
5
R.7
R.6
R.34
R.33
R.32
T.10
T.9
T.8
R.31
7
MANITOBA
UNITED STATES

PROVED AND PROBABLE SULPHUR RESERVES

The proved and probable sulphur reserves have been estimated where it is anticipated that sulphur will be recovered from the hydrogen sulphide contained in the estimated proved and probable natural gas reserves.

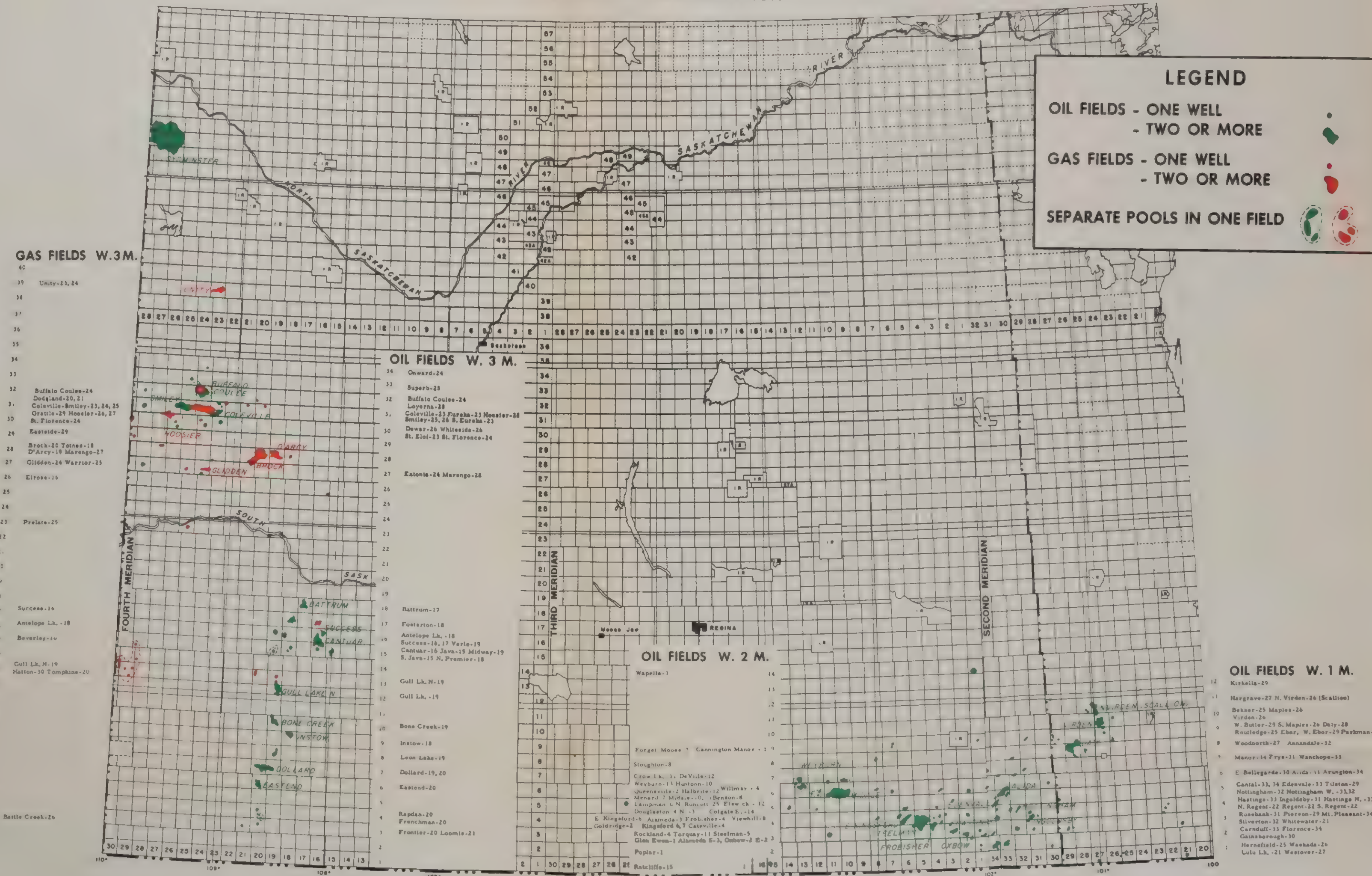
ESTIMATE OF PROVED AND PROBABLE RESERVES OF SULPHUR IN CANADA
(thousands of long tons)

	Remaining Proved Reserves as of Dec.31/57	Additional Probable Reserves as of Dec.31/57.
Northwest Territories	-	-
British Columbia	1,648	560
Alberta	28,092	39,658
Saskatchewan	87	54
Manitoba	-	-
Eastern Canada	-	-
TOTAL	29,827	40,272


GAS FIELDS
W. 5 & 6 M.
W. 4 M.
OIL FIELDS
W. 5 & 6 M.
W. 4 M.
EDMONTON
CALGARY
LESSER SLAVE LAKE
ROCKY
MOUNTAINS
FOREST
RESERVE
BLUEBERRY
B.C. & ALBERTA OIL AND GAS FIELDS
SCHEMATIC REPRESENTATION
GAS-ONE WELL
-TWO OR MORE
OIL-ONE WELL
-TWO OR MORE
SEPARATE POOLS IN ONE FIELD
JANUARY,1958

SASKATCHEWAN & MANITOBA — OIL & GAS FIELDS

SCHEMATIC REPRESENTATION



JANUARY, 1958

Possible Oil and Gas Reserves

The Arctic Islands

There are several basins in Canada that have possible oil and gas reserves. Other than the great sedimentary basin of Western Canada, the larger of these in which the potential production may be of considerable magnitude, is in the Arctic islands. Here a favourable sedimentary sequence and the presence of several salt domes similar in structure to those of the Gulf Coast of the United States are known. No wells have been drilled in this area. It is reported that oil is being produced in the U.S.S.R. opposite the Canadian Arctic islands from strata that are the extension of the same basin.

Hudson Bay and James Bay Area.

Another sedimentary basin occurs on the south and west sides of Hudson Bay and James Bay. This area is 800 miles long and from 75 to 225 miles wide, with an area of about 125,000 square miles [I]. A small part of this is in Manitoba, with the remainder in Ontario. The sediments are largely marine Palaeozoic strata with evaporites (gypsum, anhydrite, etc) overlain in part by Cretaceous beds containing lignite. In most of the area the sediments are thin, but there are areas where at least 2,000 feet are present, a thickness sufficient to give oil and gas prospects. Only a limited amount of drilling has been done.

The Southwest Peninsula of Ontario.

The Ontario basin bounded by Lake Huron, Lake Erie and Lake

I "Possible Future Petroleum Provinces of North America," Bulletin American Association of Petroleum Geologists, Volume 35, No. 2, 1951, P. 458.

Ontario, including the Manitoulin Islands, is bounded on the north and east by the Precambrian Shield which crosses the St. Lawrence river in the vicinity of Brockville. It comprises about 25,800 square miles. Only that part south and west of the Niagara escarpment stretching from Bruce Peninsula to Queenston on Niagara River, has yielded oil and gas in commercial volumes. Drilling commenced in this area in 1859, and several relatively shallow oil fields with prolific production resulted. Some of these still continue to yield oil. In recent years the area has been more intensively searched for gas rather than oil, and much greater success has been achieved than was formerly thought possible in an area where thousands of wells had been drilled. Drilling has been done in Lake Erie off the shore of Kent County with some considerable success. Less success has attended efforts to find production under Lake St. Clair. There is no doubt exploration will continue for a long time to come with moderate success. For many years the Dawn field in Lambton County has been used as a storage basin for gas imported from the United States in off peak summer periods. There are many other fields that could be developed for storage and in this the area has a tremendous significance in relation to transportation of gas from Western Canada for use in Central Canada.

The St. Lawrence Lowland.

The St. Lawrence lowland stretching into Eastern Ontario, but mainly in the province of Quebec, contains a large area of older Palaeozoic strata. Actually the area is a large basin with axis parallel to the St. Lawren

River. Its length is more than 200 miles and its width is about 60 miles near Montreal. On the southeast it terminates against the belt of disturbed rocks which are the northward extension of the Appalachians. Some recent success has been achieved in finding gas near Three Rivers, and at present several companies are engaged in active exploration. The prospects are considered reasonably good.

Gaspe Peninsula

Also in Quebec the Gaspe Peninsula has been known for more than a century to contain favourable structures in Palaeozoic rocks with numerous oil seepages. An area of Devonian rocks is known over a distance of 150 miles with a width of about 35 miles, and there are Palaezoic rocks covering Anticosti Island in the Gulf of St. Lawrence. In the period between 1860 and 1903 fifty seven wells were drilled in Gaspe, and oil in small quantities was found. One deeper well was drilled in 1913 and there have been several since 1939. The lack of success, briefly stated, seems to have been due to absence of reservoir rocks that could contain commercial accumulations of gas and oil, but there is no doubt other features are favourable and the prospects are by no means exhausted. Reef limestone in the Silurian would seem to offer the best opportunity for prospecting, but this will require deeper wells than have yet been completed.

The Gaspe area is interesting from a geological historical point of view, It was from studies in this area that Sir William Logan, Founder of the

Geological Survey of Canada, and his colleague, Sterry Hunt, propounded the anticlinal theory in 1844. The theory was quickly put to practical application in Kentucky and West Virginia with marked success and has had a profound effect on all subsequent exploration in every part of the world

Maritime Provinces

In the Maritime provinces of Canada there are sedimentary basins in New Brunswick crossing Northumberland Strait and including Prince Edward Island, and extending into a part of Nova Scotia along the northwest flank of that province. The only production so far found comes from the Stony Creek field discovered in 1909 nine miles from Moncton in New Brunswick, in this area are also the Albert Oil shale deposits. These were evaluated by drilling during the last war by a total of 79 holes, aggregating 24,554 feet, but of three areas drilled, only in the Albert Mines area were results encouraging. In this area it is estimated[I] that there are "100,000,000 tons to a depth of 400 feet averaging 10.6 gallons, and of this tonnage about 2,000,000 tons average 20 gallons. However, to take out the higher grade shale by open-cut methods would involve excavating 20,000,000 tons of shale and it is estimated that the average oil content of this material would be 12 to 14 gallons to the ton."

More than 30 wells have been drilled in New Brunswick in an attempt to find oil and gas beyond the Stony Creek field, but without success. The deepest well in the sedimentary basin drilled in 1945 to a depth of

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I Summary of Investigations on New Brunswick Oil Shales, Canada, Department of Mines and Resources, Bulletin No. 825, P.2.

14,696 feet, was on Prince Edward Island in the Hillsborough Bay area. The succession was red beds with evaporites and it was not penetrated.

In Nova Scotia a number of wells have failed to penetrate the salt section, even though depths in excess of 6,000 feet were reached and one well reached a depth in excess of 11,500 feet. Seepages of oil are known to have occurred on Cape Breton Island and oil shales occur in Mississippian and Pennsylvanian rocks.

Newfoundland.

In Newfoundland there are several sedimentary basins, but the most promising one is on the west coast near Parsons Pond and St. Paul's Inlet where seepages occur. Actually a few hundred barrels of oil have been produced from wells drilled some years ago. This area recently has been under active exploration.

Some Small Western Canada Basins

Other than the great interior sedimentary basin there are a few small basins that have come under exploration from time to time in Western Canada. Among these is the Flathead area of Southeastern British Columbia with some remarkable oil seepages issuing from Precambrian strata which are overthrust onto Mesozoic and Palaeozoic strata. There is also the Fraser River delta area near Vancouver where there is an unknown thickness of Tertiary strata believed to be mainly, if not wholly, non-marine, and in which some drilling has been done with reported shows of gas. Sedimentary rocks, mainly of Cretaceous age, occur on the Gulf Islands near the south-east coast of Vancouver Island. Also on the Queen Charlotte Islands, where oil seepages and oil shales are present, there are Tertiary, Cretaceous and Jurassic strata.

In all of these areas a limited amount of drilling has been done and although the prospects are by no means exhausted, they are considered to be much less favourable than in the great interior basin.

The Western Canada Sedimentary Basin (Figure 1)

As herein defined the Western Canada sedimentary basin is an extension northwestward of the great interior basin of the United States. It is the area south and west of the Precambrian shield and east of the Cordillera. At the international boundary between Canada and the United States it is about 800 miles wide. In the Peace River area it is about half this amount and 1,600 miles northwest of the international boundary, in the vicinity of the delta of Mackenzie River, it is about 235 miles wide. It consists of the southwest corner of Manitoba, the southern half of Saskatchewan, all of Alberta with the exception of the northeast corner, an area in the foothills in south-eastern British Columbia and all of the area east of the mountains in the northeast part of that province, a small part of southeast Yukon as well as Eagle and Peel plateaus and the Porcupine area, the Mackenzie River drainage area between the Precambrian shield on the east and the mountains on the west in the Northwest Territories northward to the Arctic Ocean.

In such a large area there are various ways in which an estimate of the possible oil and gas reserves may be made. Perhaps the most satisfactory and reliable method is that of estimating the volume of sediments within the basin and comparing this with other sedimentary basins of the world or other areas in a more advanced state of development. Lewis G. Weeks, Standard Oil Company (New Jersey) has for a number of years

Figure 1. North America, showing main physiographic divisions.

made extensive studies of this method, and his results have been revised and published [1] from time to time. According to him, up to January 1, 1950, the oil discovered in the United States amounted to nearly 64 billion barrels, of which 39 billion had been produced, leaving 25 billion as proved reserves. This amounted to 32,000 barrels of oil per cubic mile in the approximately 2 million cubic miles of effective basin sediments. The figures for the various states as prepared by him at that time, were as little as 6,000 to 8,000 for Kentucky and Indiana, and as much as 200,000 barrels of oil per cubic mile for California. At that time, also, he considered the ultimate for the United States might be 110 billion barrels or 50,000 barrels per cubic mile, and that the world basin areas of approximately 20 million cubic miles might have an ultimate production of 610 billion barrels or 30,000 barrels per cubic mile. This figure of 30,000 barrels per cubic mile has been widely quoted by geologists and engineers to whom it offered a ready yard-stick of measurement.

Since 1950, however, Weeks has revised his estimates for the ultimate amount of oil to be discovered in the United States. This has been done as the result of new information, but particularly because of the present assessment of lands under water on the continental shelf. He now considers the ultimate oil to be discovered in the United States will exceed 200 billion barrels. Others, using good supporting arguments, have thought that 250 billion barrels is more probable, and the United States Bureau of Mines has considered 300 billion barrels a reasonable assumption.

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1. Weeks, Lewis G., "Concerning Estimates of Potential Oil Reserves" Bulletin of the American Association of Petroleum Geologists, Volume 34, No.10, Pp. 1947-1953.

These upward revisions have been supported by the amount of oil found. To the end of 1956 the United States had produced 55.2 billion barrels of oil, and the reserves at that time were estimated at 30 billion barrels of crude oil and 5.4 billion barrels of natural gas liquids, or a total [1] of 35.4 billion barrels. Thus production and proven reserves at the end of 1956 amounted to 90.6 billion barrels.

In regard to discoveries of natural gas, the figures have had to be revised upward as more geological facts have become known and a better assessment could be made. The ratio of the rate of gas discovery to oil discovery has had to be increased, since it is now known that there has been "a rise from 4.1 Mcf of gas per barrel of oil reserves found in 1947 - 1949 to 6.5 Mcf per barrel found in 1954-1956." It has also been calculated by Terry and Winger[2] that "based on the estimate of 250 billion barrels of minimum ultimate oil recovery (in the United States) and deducting 86 billion discovered to date, there would remain 164 billion barrels to be found in the future. At 6 Mcf per barrel, this would indicate future gas discoveries of 984 trillion cubic feet. Adding proved reserves of 238 trillion at the end of 1956 indicates a total future gas supply of the order of 1,200 trillion cubic feet which we propose as a reasonable minimum estimate based on present evidence."

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1. World Oil, February 15, 1957, P.130.
2. Terry, Lyon F. and Winger, John G., American Gas Association meeting Lake Placid, May 13, 1957, published by Chase Manhattan Bank.

It is not possible to get exact figures of total gas production to date in the United States. Cnly estimates are available prior to 1906 and the amount of waste is unknown. However, to the end of 1956 reliable information [1] shows that marketed production has been about 140 trillion cubic feet. Thus marketed gas to date plus proved and future supply estimates, amounts to 1,300 to 1,400 trillion cubic feet. If the ultimate oil yield is taken as 250 billion barrels, this tends to confirm the opinion that for every billion barrels of oil discovered, it may be expected that there will be about 6 trillion cubic feet of gas, as has been indicated in the more recent years.

Against this background of data from the United States, the most highly developed oil and gas country in the world, a broad assessment of possible gas and oil resources of Canada is feasible. The importance of the estimate will not be in the precision of the amount deduced, provided it is within reasonable limits, but it will be in the magnitude of the reserves which are indicated.

In Canada although limited production may be achieved in any one of a number of sedimentary basins, the only really favourable prospects for large ultimate yields are in the sedimentary basin, which is the northwest extension of the interior plains area of the United States, and in the Arctic Islands.

The sedimentary basin in the western provinces consists of an area 800 miles wide at the international boundary between Canada and the United States stretching from the Precambrian Shield in Manitoba on the

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1. World Oil, February 15, 1957, Pp. 183-184.

east to the Cordillera on the west. Northwestward this area extends 1,600 miles to the delta of Mackenzie River. At the Arctic coast its width is about 235 miles.

In this area the thickness of sediments in general increases westward or southeastward. For purposes of computing the volume only that area west of the 1,000 foot isopach has been used, as in Figure 2. In the foothills as shown on the map, the volume has been calculated on a basis of 16,000 feet, since wells in this area have already reached depths of 15,000 feet. This does not by any means represent the total thickness of sediments in this area. A planimeter measurement of size of areas and volume of sediments in each is as follows:[1]

	SIZE square miles	VOLUME OF SEDIMENTS (thickness 1000 to 16,000 feet) cubic miles
Manitoba and Saskatchewan	176,623	168,072
Alberta Plains	223,697	301,731
Alberta Foothills	13,196	39,984
British Columbia Plains	36,026	70,892
British Columbia Foothills		
South	2,095	6,348
North	12,567	38,078
Yukon	43,000	64,500
Northwest Territories	204,794	267,133
Total for sedimentary basin	711,998	956,738

The average thickness is slightly more than 7,000 feet.

1. These areas are here given separately so that they may be useful where more restricted comparisons of one part of the basin in reference to other parts are desired.

With the above information it is now possible to make estimates of the potential oil and gas reserves in the sedimentary basin of Western Canada as thus defined. It should be noted that these figures are applicable only to the basin as a whole and not necessarily applicable in the same way to individual parts. In reference to world basins, as already indicated, Weeks in 1950 used 30,000 barrels of possible oil for each cubic mile of sediments. His figure for the United States at that time was 50,000 barrels of possible oil for each cubic mile of sediments. This figure has subsequently been revised upward. Thus these figures are now believed to be too low. They, therefore, can be regarded as minimum figures.

On the world basis of 30,000 barrels of possible oil for each cubic mile of sediments, it is obvious that an estimate for the Western Canadian sedimentary basin of 950,000 cubic miles would be approximately 28.5 billion barrels of possible oil, whereas if the comparison is made with the minimum figure of 50,000 barrels for the United States, the corresponding figure would be approximately 47.5 billion barrels. Again it should be emphasized that these are minimum figures which are too low as applied to the United States.

An estimate of maximum figures would be more hazardous. In the United States a great amount of prolific production has been found in Tertiary strata which in Canada are expected to be generally barren of oil because of their non-marine character. Thus it is not possible to use a direct relationship between the size of the basins in Canada and in the United States. Many other factors also need careful assessment, but

based on a possible evaluation of 250 billion barrels in the United States, which is stated by Terry and Winger to be a "minimum ultimate oil recovery", it would seem that an estimate of 75 to 100 billion barrels would not be too high for Western Canada and might be below maximum possible yields. Thus based on minimum and what are regarded as below maximum estimates it is concluded that the ultimate recoverable oil of the Western Canadian sedimentary basin is of the order of 50 billion barrels. This estimate is exclusive of the bituminous sands of Northern Alberta.

There is another approach by which the validity of the 50 billion barrel estimate can be checked. This is the relationship between wells drilled and the amount of oil found and a comparison between Canada and the United States.

It has been shown[1] that in the United States the development of new oil per well has remained reasonable constant in the 30-year period 1925 to 1955. The figures are as follows:-

	1925-35	1935-45	1945-55
New Oil - billion barrels	17.4	20.8	30.9
Total wells completed	220,400	279,700	435,100
New oil per total well	79,000	74,000	71,000
Oil wells completed	127,500	166,400	231,700
New oil per oil well	137,000	124,000	133,000

This shows that "in terms of results per well drilled only a slight downward trend is evident over the past 30 years and this trend may be checked or reversed for the next ten years by the high results per well expected from offshore drilling".

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1. Gonzalez, Richard J. (Director and Treasurer, Humble Oil and Refining Co.) "U.S. Not Running Out of Oil" World Oil, March, 1957. P. 65.

In Western Canada to the end of 1957 there have been a total of approximately 22,000 wells drilled, resulting in the finding of about 3.8 billion barrels of oil of which 2.8 billion barrels are present reserves of crude oil exclusive of natural gas liquids. This is a discovery rate of about 170,000 barrels of oil for each well drilled in comparison with the United States figure of from 70,000 to 80,000 barrels over the 30-year period from 1925 to 1955. Since the beginning of the oil industry to the end of 1956 in the United States a total of 1,646,000 wells[1] had been completed discovering 90.6 billion barrels in oil produced and in proved reserves. This is equivalent to the discovery of about 55,000 barrels per well in comparison with the 70,000 to 80,000 for the 30-year period. In Western Canada to the end of 1957 there were 12,250 oil wells drilled developing approximately 3.8 billion barrels of oil or an approximate total of 310,000 barrels for each oil well. This is in comparison with around 130,000 barrels for each oil well in the United States in the period 1925 to 1955. Thus from the standpoint of both total wells and oil wells drilled, the discovery rate in Western Canada for its short history has been better than in the considerably longer period in the United States. Thus there is a considerable margin of safety in making the assumption that the discovery rate in Canada for many years to come will be at least the equivalent of what it has been in the United States over a long period. On this basis, therefore, and in relation to a comparison of volume of sediments in the two countries, Western Canada's ultimate reserves may

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1. World Oil, February 15, 1957. P. 145.

be expected to be one quarter to one third those of the United States. If the figure of 250 billion barrels is used for ultimate reserves for the United States, then the Western Canadian ultimate reserves, using the more conservative figure of one quarter, would be more than 60 billion barrels. If the Bureau of Mines figures of 300 billion barrels is used for ultimate reserves of the United States, then the corresponding Western Canadian figure on the above basis would be 75 billion barrels. The figure of 50 billion barrels for Western Canada, therefore, seems to be in accord with present available information using figures which are conservative.

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It has already been shown that a figure of 6 trillion cubic feet of gas is being found in the United States for each billion barrels of oil. In view of the prospects for gas, as already shown by discoveries, and in view of geological opinion, particularly in regard to foothills structures, this figure does not seem too high for Canada. Applied to the minimum figures of 28.5 billion to 47.5 billion barrels of oil, the minimum figures for possible gas reserves would be 170 to 285 trillion for the Western Canadian sedimentary basin. Applied to the more reasonable figure of 50 billion barrels, it would be 300 trillion cubic feet. Even this higher figure of 300 trillion is slightly lower than a quarter of what is being predicted for the ultimate figure in the United States where, in spite of a considerably greater density of drilling than in Canada, the finding of 24.9 trillion cubic feet [1] of new natural gas

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1. Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas. Vol. No. 11. American Gas Association - American Petroleum Institute. Dec. 31, 1956.

reserves during 1956 constituted the largest single discovery year in the history of gas development in that country. It is also reported [1] that "in the period 1951-1955 in the United States 82.5 trillion cubic feet of new natural gas reserves were proven to exist. In the preceding five-year period covering 1946- 1950 new gas found totalled 67.3 trillion cubic feet". This is a discovery of almost 150 trillion cubic feet in 10 years. This period corresponds to the decade in which there was a tremendous expansion of the natural gas industry in the United States, and in which the value of natural gas received greater recognition than had previously been the case. There is no doubt, therefore, with proper incentives the natural gas industry of Western Canada can have a similar proportional expansion in the next decade, since it can be stated with a high degree of confidence that the ultimate amount of gas to be discovered in the Western Canadian basin is of the order of 300 trillions of cubic feet.

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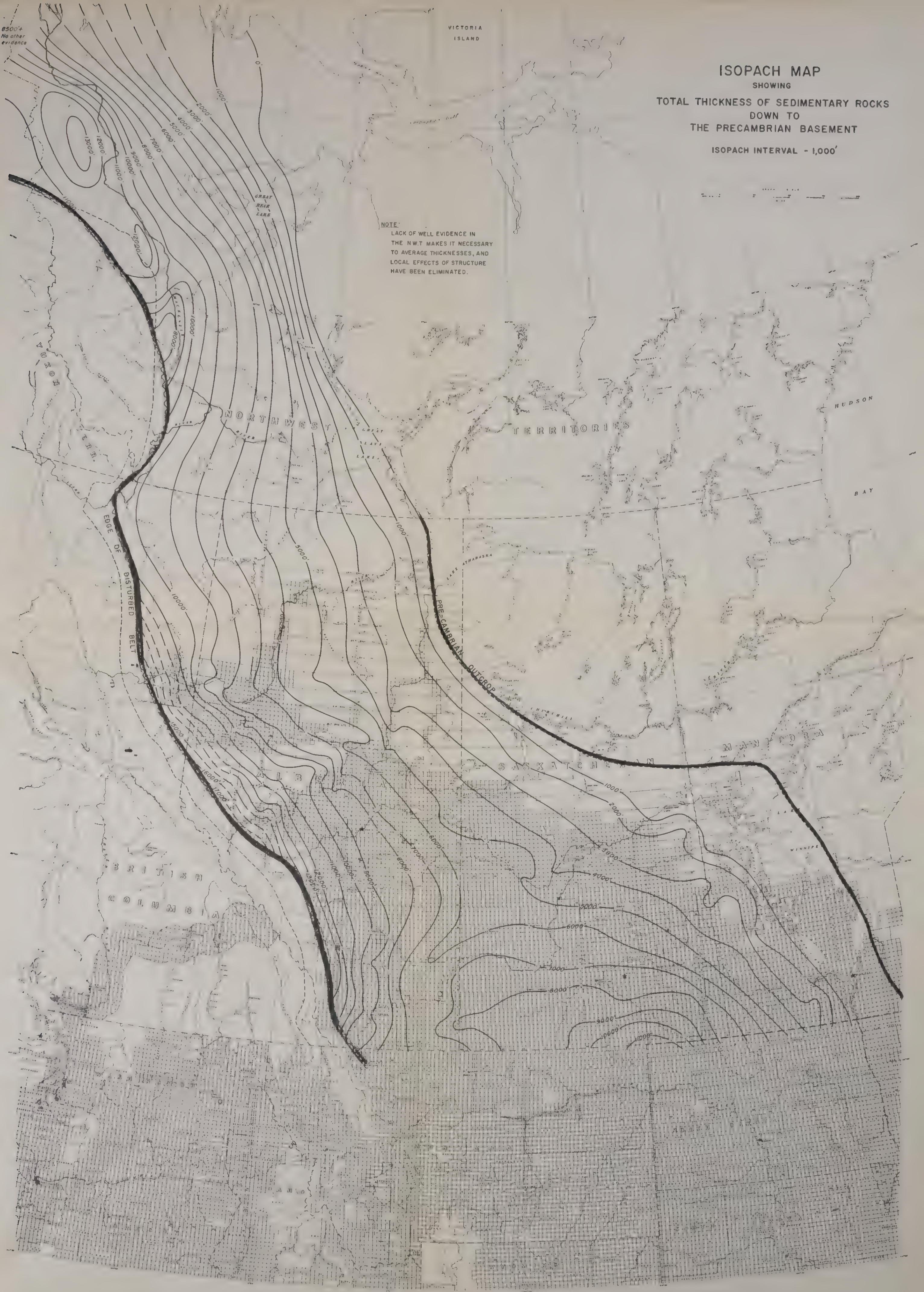
1. World Oil , February 15, 1957, P. 136. -7

Possible Sulphur Reserves.

The calculations for possible sulphur reserves in Western Canada are based on the possible gas reserves of 300 trillion cubic feet as worked out for Western Canada. Because of the variation in per cent of sulphur from area to area; for example, sulphur percentage in the foothills is generally much greater than in most parts of the plains; a rough breakdown of possible gas for Western Canada was made to aid in arriving at the sulphur figures.

	Sulphur (Millions Long Tons)
Manitoba & Saskatchewan	5
Alberta - Plains	65
- Foothills	125
British Columbia	35
Yukon & N.W.T.	30
TOTAL:	260

The above sulphur reserves do not take in the huge amounts of sulphur in the McMurray oil sands. Using a figure of 150 billion barrels of oil and 4 to 5 per cent sulphur, 60 per cent recoverable, would result in a figure of approximately 900 million long tons of sulphur for McMurray oil sands.


ISOPACH MAP
SHOWING
TOTAL THICKNESS OF SEDIMENTARY ROCKS
DOWN TO
THE PRECAMBRIAN BASEMENT
ISOPACH INTERVAL - 1,000'
NOTE:
LACK OF WELL EVIDENCE IN
THE N.W.T MAKES IT NECESSARY
TO AVERAGE THICKNESSES, AND
LOCAL EFFECTS OF STRUCTURE
HAVE BEEN ELIMINATED.
8500'+
No other
evidence
VICTORIA
ISLAND
GREAT
BEAR
LAKE
NORTHWEST
TERRITORIES
GREAT
SLAVE
LAKE
HUDSON
BAY
EDGE OF DISTURBED BELT
PRE-CAMBRIAN OUTCROP
LAKE ATHABASKA
SASKATCHEWAN
MANITOBA
BRITISH
COLUMBIA
YUKON
TERR.
ALBERTA

THE ATHABASCA BITUMINOUS SANDS

The bituminous sands of the McMurray, Alberta, area are 300 miles northeast of Edmonton. The first white man known to have seen them was Peter Pond in 1788. Since that time they have been a source of wonder and amazement to many explorers and scientists. They are exposed in the valley of Athabasca River and on its tributaries for a distance of 42 miles above McMurray and 76 miles below it. Prominent cliffs along the Athabasca River ooze a thick tarry bitumen on warm summer days and even a casual observor cannot fail to be impressed by the magnitude of the oil deposit. Actually its size is not too well known. At McMurray and in places along Athabasca River to the north, the base of the bituminous sands is exposed in contact with Devonian limestones, but south and west the regional southwest dip causes the sands to become covered by progressively thicker younger strata. The last outcrop up stream on Athabasca River is, therefore, the top part of the formation. Drilling beyond the limits of the exposures has given some additional information, but only a few wells have penetrated a section comparable to that exposed and, as far as known, all wells have encountered much thinner sections. Thus the deposit wedges out south and west as it does also to the east. This is to be expected, since the sands in which it occurs form a deltaic Cretaceous deposit probably laid down at the mouthof a large river originating in the Precambrian shield to the east.

S.C. Ells[I] of the Mines Branch, Department of Mines, Ottawa, did much work in mapping, sampling and testing the bituminous sands by shallow auger holes.

I Ells, S.C., Department of Mines, Mines Branch, Bulletin No. 632, 1926, P. 16.

He stated that "the direct distance in a north and south direction through which outcrops have been noted, is approximately 115 miles, and that from east to west approximately 55 miles". It should be noted that this is only the exposed part. According to Max Ball,[1] who for many years carried out operations at McMurray for Abasand Oils Ltd., the areal extent is 10,000 to 30,000 square miles. A bed 100 feet thick with a bitumen saturation of 10 per cent contains 133,000 barrels an acre ~~of~~ or 85,120,000 barrels per square mile. The maximum thickness[2] of the deposit, as far as known, is 224 to 229 feet, all high grade material, recorded in holes B.17 and B.33 in the Mildred - Ruth Lakes area, about 22 miles north of McMurray on the west side of Athabasca River opposite the mouth of Steepbank River. In many areas, however, as shown by drilling, even where the total thickness of the bituminous sand formation may approach 200 feet, there are bands of clay in places of very considerable thickness, interbedded with sands containing variable amounts of bitumen. All these conditions make an estimate of the total content of bitumen very difficult and in consequence, not too precise. It is thus not surprising that the most reliable estimates place the bitumen content in the order of 100 to 300 billion barrels, with perhaps 250 billion barrels the preferable figure.[3] The amount of bitumen in this deposit, therefore, may exceed the known free world's proven oil reserves, which, as of January 1, 1957, were considered[4] to be 207.5 billion barrels.

I Ball, Max W., "Development of the Athabasca Oil Sands," Transactions, Canadian Institute of Mining and Metallurgy, Volume 44, 1941, P.64.
2. Hume, G.S., "Results and Significance of Drilling Operations in the Athabasca Bituminous Sands." Transactions, Canadian Institute of Mining and Metallurgy, Volume 50, 1947, P.312, 323.
3. Pratt, Wallace E., "Oil in the Earth, "University of Kansas Press, 1943, P. 41.
4. World Oil, August 15, 1957, P. 199.

In regard to fuel value 100 billion barrels of oil is equivalent to 24 to 25 billion tons of coal. This is about the amount of recoverable coal estimated by Mackay[I] for the reserves of Alberta. Thus the minimum reserves of oil in the bituminous sands is equivalent in heat value to all the recoverable coal in Alberta.

Extensive drilling of the bituminous sands was undertaken during the war by the Department of Mines and Resources, Ottawa, at the request of the oil Controller for Canada. A number of areas north of McMurray including the Horse Creek reserve, were tested. The drilling in 1942 was by auger hole method, which was not satisfactory, and from 1943 to January 1947, core drilling, which had been perfected, was used in drilling 291 holes for a total of 53,918 feet. Certain requisites were considered necessary for a possible commercial deposit, which was then envisioned as an open-cut mining operation. These were, briefly :--

(1) A small thickness of overburden

(2) Sands with low clay content and a bitumen content of not less than 10% and preferably greater than 12%.

(3) Continuous thickness of sands without extensive interbedded bands of clay.

(4) Favourable plant site area.

(5) Adequate tailing disposal area.

The results of drilling indicated a surprising variation in the bitumen content from place to place, and even in the same deposit. The most favourable condition found were in the Steeprock River area and in small areas on Horse River, but particularly in the Mildred - Ruth Lakes area, 22 miles north of McMurray. The area at the plant at Bitumont was not tested.

I Report of the Royal Commission on Coal, 1946, P.II

The Mildred - Ruth Lakes area proved to be phenomenally rich. In parts of it the drill holes were on a quarter of a mile spacing, and in other parts onve half mile. In a limited area the quarter mile spacing was supplemented by a hole in the centre of the quarter mile area, as well as a hole at each quarter mile corner. The amount of bitumen was found to vary from a few per cent to bitumen beds in the sands containing 77.8% bitumen. For these richer beds all assays were calculated as 19%, the theoretical maximum content where the sand grains would be in contact with one another. In outlining the Mildred - Ruth Lakes area a total of 73 wells from 125 to 300 feet deep were drilled in an area 8 miles long by 2 miles wide. Forty eight of these holes were concentrated in an area of 2 1/2 square miles. Nine wells more widely spaced were drilled south of the more favourable area, increasing its size to 4 1/2 square miles. In this a calculation based on all assays (using 19% as maximum) showed there are 900,000,000 barrels of bitumen. These, then are proven reserves in this area amounting to 200 million barrels per square mile for the 4,1/2 square miles in which the content was appraised. It was found that the sands in this area have an average of 13.6% bitumen and that the ratio of bituminous sands to overburden is 2.6 to I. This, then, is a rich deposit that fits all the requisites for possible commercial use. There is a limestone bench about a quarter to a half mile wide between the escapment face of the deposit and Athabasca River, which would provide an adequate plant site. The deposit is wholly above river level, which would simplify drainage in open pit mining. Also all material from the deposit would be transported <u>down</u> to the plant, which would not be the case where a plant site had to be made on the top of a deposit as in some other areas.

Since the Mildred - Ruth deposit was outlined by drilling, a number of oil companies have taken permits on areas of bituminous sands and have done drilling. It is known that some of these programmes have met with satisfactory results, even though equally rich deposits over such a large area as that on the Mildred - Ruth Lakes area, may not have been discovered. Thus although there are no total figures for proven amounts of bitumen, they are probably large. Actual figures, however, would not be significant unless the grade of material and the amount of overburden was known, because a proven deposit might have no value if conditions were prohibitive for open pit mining, which up to now has been considered to be the method most likely to be used in any development. Open pit mining has many disadvantages, and there is no doubt that extraction in situ would constitute the ideal method which would make the thousands of square miles available for development, instead of the possible 10 to 20 square miles, as estimated by Max Ball.[I] If open pit mining is considered, obviously only the proven bitumen within this small area in sands of sufficient grade to be commercial under small oberburden, would have any importance. The amount of bitumen in this, however, would still be reckoned in billions of barrels.

I Ball, Max W., "Development of the Athabasca Oil Sands," Transactions, Canadian Institute of Mining and Metallurgy, Volume 44, 1941, P.66.

Methods of extraction in situ rather than by open-cut mining would change the whole situation and make at least 100 billion barrels the minimum estimate for the deposit, available for development. Such methods of extraction are believed to be under serious laboratory investigation, but so far no application has been attempted. The problems of extraction and treatment of the bitumen are only a part of the difficulties. The percentage of bitumen in a deposit is commonly calculated by weight. Thus when a deposit is said to contain 15% bitumen, the other part is 85% sand with variable amounts of clay. The sand, when the bitumen is extracted, is clean and white and much of it is very fine. It could be handled from a plant as a sludge in water through a pipeline, but its confinement to a disposal area might involve high expenditures. The necessary measures would have to be taken to see that the sand did not reach Athabasca River, where shifting sandbars are now a problem of navigation at certain stages of water. Also the sand when dry would be air borne by the wind, so that perhaps some form of a consolidating agent would have to be provided to hold it. As a sludge it would be expensive to try and put it back in the mined out area, unless unmined bituminous sands were left as walls to retain it. This would reduce the mineable sands in any area by a considerable amount and thus leave behind an appreciable volume of bituminous sands that would never be recovered, a method that would not be considered good conservation practice. Thus removal of the bitumen in situ is desirable, even though the recovery would not be complete.

The layman is often puzzled as to why the bituminous sands are not now being developed. The answer is largely two fold, namely, mining extraction and treatment methods, that is, the necessary techniques and

over-all costs. There is no doubt at the present time that if an emergency should arise where costs were considered of less importance than production of oil, sufficient information and knowledge is available for mining the sand and designing plants for the extraction and treatment of its bitumen content. It has been considered[I] that the economic plant size would be 20,000 barrels a day, but this need not necessarilybe so. However, to attain a commercial operation it might be necessary to operate not less than 5 such units and thus provide 100,000 barrels a day in order to afford economic transportation by pipeline to the nearest point where other pipeline facilities could be used to market the oil. In this case the nearest outlet would be Edmonton and the Interprovincial and Trans Mountain pipelines. Such an operation thus involves a treatment plant in the bituminous sand area which would refine the bitumen only to the stage where a crude oil would be available for pipeline transportation. In this process the 5% sulphur content would be eliminated.

The building of one to five 20,000 barrel a day units would take considerable time and involve large capital expenditures. Perhaps part of the reason why no atte mpts have been made so far to put a plant in operation, is the fact that obsolescence of such a plant might be very fast due to rapidly improving techniques, particularly in the refining industry. The matter of cost in terms of only a few cents a barrel is vital. For example, the assumption is made that the unrefined bitumen taken from the Mildred-Ruth Lakes deposit has a value of $1.00 a barrel, a reduction of each cent in costs for the 900,000,000 barrels involved means 9 million dollars.

I Blair, S. M. Report on the Alberta Bituminous Sands, Government of the Province of Alberta, 1950.

Under such conditions a pilot plant operation for a limited time is highly desirable, but such a pilot plant must be on a reasonable scale, in which case the disposal of the crude pipeline oil thus produced becomes a major expense in the period pending a commercial operation.

These are only a few of the problems facing the development of the bituminous sands. They have been outlined here briefly because they completely overshadow the problem of the amount of established or possible reserves. The Mildred - Ruth Lakes deposit is sufficient for a 100,000 barrel a day operation for nearly 30 years, and there are other valuable and rich deposits at Bitumont and elsewhere. Thus there is no problem in the availability of large volumes of rich sands. An in situ extraction method, however, if such is devised, could operate south of McMurray and hence avoid some costly transportation problems such as the crossing of the Athabasca River, unless it is decided to build the proposed railroad to more northerly areas via McMurray, rather than by one of the other routes that have been considered. At the present time there is also the difficulty of availability of a market for crude oil produced in Alberta. A plant to produce crude oil from the bituminous sands would probably take two to five years to complete after the decision had been made to proceed with such a development. This, then, brings up the problem of the availability of future markets for crude oil, and it would seem almost certain unless some solution is found, that the incentive for present development of the bituminous sands will be lacking. This, of course, does not mean that further investigation of cheaper production and treatment methods will not be studied. Progress will, however, only be made because of the firm belief that in the next decade or so oil will be in demand in ever increasing amounts, and that a larger share of the market than now will be available for that

produced in Alberta. This assumption however, may need careful analysis. Rapid changes are taken as inevitable. The widespread and abundant use of oil and natural gas has given the coal industry in Alberta almost a solar plexus blow. There are reliable reports of the near introduction of cheap energy by nuclear fusion, which might conceivably be a sharp competitor in the near future to oil and gas for certain purposes. There is no doubt, however, that oil will retain its favoured position long after nuclear power has been made available, and if markets are established, they will not be lost. On the other hand, it would appear that the competitive position of oil and gas in the markets of tomorrow in reference to other sources of energy,

could become much more severe than it is in reference to sources of energy in the markets of today, so that the problem of the establishment of markets and their retention is of paramount importance in providing an incentive for the development of the bituminous sands which, with the exception of radioactive deposits and excluding coal, is the greatest source of energy available in Canada. The problem of the bituminous sands, therefore, if they are to be developed, is not one of reserves, but of incentive for development, and this incentive can only be provided by assured future markets for oil and gas.

FREEHOLD LANDS:

The term freehold as used herein applies to mineral rights owned by individuals but is not intended to apply to the mineral holdings of the two major railway companies and the Hudson's Bay Company, nor does it apply to the sizeable holdings of smaller land holding companies such as the Calgary and Edmonton Corporation. All of these rights are the result of homestead purchases from the Federal Government, the railway companies and the Hudson's Bay Company, made in the latter part of the nineteenth and very early years of the twentieth century. These main land holding bodies began reserving mineral rights to themselves between the years 1887 and 1905. Thus a present day freehold mineral map provides an accurate picture of the history of Prairie Settlement up to the early part of this century.

Although accurate figures are extremely difficult to calculate it is probable that individual or farmer-owned minerals in the sedimentary basin of Western Canada total some 30 millions of acres. While this total acreage is small, representing as it does only 6 or 7% of the total acreage in the basin, its geographic distribution has given it an importance disproportionate to its volume. This is the result of the early discoveries in the "fairway" area of Alberta which is an area running from a few miles northwest of Edmonton, southeasterly through the Camrose and Stettler districts, and later intensive exploration and development in what is commonly referred to as the Souris Valley of southeastern Saskatchewan. The Edmonton and Souris Valley areas are areas of early settlement and therefore contain a relatively high percentage of freehold minerals. Conversely of course there is no freehold acreage in the northern parts of Western Canada, thr Northwest Territories and the Yukon. Thus, while freehold acreage if evenly distributed throughout the sedimentary basin would

amount to about two sections per township, in the areas of early settlement it runs as high as 14 to 18 sections per township.

Freehold or farmer-owned minerals do therefore play an extremely important part in the overall land picture.

The oil industry in Western Canada has for the most part adopted the " unless " type of lease. This form of lease is the evolutionary result of many years of experimentation in the United States, where the predominance of freehold ownership in the oil producing areas has necessitated the development of a form of lease which is mutually satisfactory to the owner and the industry.

Basically, the "unless" type lease provides a short definite term, commonly ten years, with a proviso that the lessee shall either commence drilling within a stated period, usually one year, or pay rent, but he is not obligated by his contract to do either. Failure to drill or pay the rental automatically terminates the lease. A "thereafter" clause extends the definite term for the producing life of the property.

The lease provides for a gross royalty to the owner of a stated percentage or fraction of production, usually one-eighth and usually contains express covenants to protect the land from drainage.

Most of the negotiations center around the bonus or consideration paid for the granting of the lease and this amount varies widely depending on the stage of exploration, proximity, to production, etc. In the early stages of exploration in Western Canada 10¢ per acre was a not uncommon amount. Following the discoveries in Alberta in the years 1947 to 1950 Industry

competition and the ordinary application of the law of supply and demand resulted in a sharp increase in the price of freehold acreage and $100.00 per acre was not uncommon for land which was highly speculative, or in Industry terminology "wildcat" acreage.

As stated previously the definite term commonly used is ten years but this is one of the negotiable features of the lease and may be varie if circumstances warrant.

Generally speaking it may be stated that the mineral owner is offered the faur "going rate" for a lease of his minerals for a definite term and is paid an annual rental during that term if the lessee fails to drill. He is assured of protection against drainage of his property and receives a gross royalty on one-eighth of the proceeds from production from his land.

In addition it is general practice in Western Canada to pay the mineral owner an additional separate amount for the use of the surface of his land for the purpose of drilling wells and erecting production facilities.

There are of course variations of the basic lease form and there are other types of Petroleum and Natural Gas Leases in existence, but for purposes of this brief no attempt has been made to catalogue these. This outline is intended to illustrate generally the basis on which the Industry deals with the individual freehold owner of petroleum and natural gas rights in Western Canada.

PRODUCTION AND CONSERVATION

Maximum Permissible Rates of Production

It has been mentioned that the amount of oil which will be recovered from a reservoir is a function of several things. One of the most important of these is the nature of the forces acting within the system. Another parameter which may be very significant is the production rate. Experience has shown that excessively high production rates can reduce the recovery efficiency appreciably below what it would be if lower rates were used. In the case of oil fields this effect is mos serious where high rates cause large volumes of gas or water to enter the producing well directly from a gas cap or aquifer. Once these fluids have gained entry to a well bore their paths often cannot be blocked by remedial measures and they will contin ue to be produced to the exclusion of crude oil. This phenomenon, known as Fingering or Coning, results in wasteful use of the available energy and can prematurely lower the oil production rate below the economic level and force abandonment earlier than would otherwise have been necessary. The same situation is true in gas reservoirs that are underlain by water.

Conservation agencies in V estern Canada recognize that production rates must be controlled to prevent wasteful practices. Each of the four western provinces has regulations designed to limit the production rate from an oil well to a level which is considered safe. These upper limits are referred to as Maximum Permissible Rates or MPR's. They are functions of the reservoir rock and fluid characteristics, the type and strength of the drive mechanisms, the well spacing, and the portion of the reservoir that has been developed. British Columbia, Alberta, and Manitoba assign each well in a reservoir the same MPR which is calculated using average characteristics for the reservoir in question. Saskatchewan makes a separate MPR calculation for each well based on the properties of that well. The folmulae used by the different Provinces are essent-

ially the same and involve comparing the characteristics of a particular reservoir or well to the properties of a standard well. The resulting answers are generally a good indication of the upper limit of a well's ability to produce efficiently. The method is particularly valuable in the early life of a reservoir when little is known about the various properties that affect recovery.

As more is learned about the characteristics of an oil reservoir and the forces acting within the system, it is often possible to make a more accurate calculation of the safe production rate using engineering principles and experience. When this approach is employed the answer that is obtained is the Maximum Efficient Rate, which is defined as the highest rate that may be maintained for an appreciable period of time without creating substantial waste. This value, commonly abbreviated MER, should not be misconstrued as a most efficient rate - it is regarded as the upper limit of a range of efficient rates. Any increase above this limit will cause avoidable waste; whereas any decrease will not significantly raise the ultimate recovery. When an MER calculation has been accepted by a conservation agency, the value will then be published as the official MPR for the oil wells or pool in question.

The situation with regard to establishing maximum rates of production from gas wells is not as clearly defined. Alberta has an MPR formula for gas wells but this has only been applied in two fields. In the remaining fields it is apparently the practice that any maximum rates are established in meetings between the Conservation Board and the operators. In British Columbia the maximum production rate is made equal to 25 percent of the well's absolute open flow potential.

Since oil and gas occur together, it is possible to have a conflict of interest between the operators in an area where an oil reservoir is in contact

with a large gas cap. Those who will derive a majority of their income from gas sales might wish to see the gas produced as quickly as possible even if such production will lower the ultimate oil recovery. On a unit-volume basis, oil is considerably more valuable than gas. Also, it is known that if the gas cap is in good communication with the oil zone, the recovery of oil will be greatest if all gas is retained in the system until the oil zone has been depleted. On the other hand, production of oil will not lower the amount of gas that can be recovered. Thus, as a general rule it is assumed that oil production will take priority over gas. However, in the special case of an extremely large gas cap in contact with very small oil reservoir, it is possible that some gas production would be permitted, if it could be shown that the value of any lost oil recovery was insignificant.

Productivity and Prorationing

One of the fundamental necessities for conservation is that the volume of oil and gas produced must not exceed the market demand. The present situation in Western Canada is that the demand for Alberta crude oil is less than the Provincial productivity. As a result, the available market must be prorated among all fields in Alberta. Prorationing is not yet considered necessary by the other Provincial Governments.

In Alberta, and other provinces, the total productivity of an oil reservoir is not necessarily equal to the sum of the MPR's for each well in that reservoir. In some cases the MPR assigned to a well will be much higher than that well's ability to produce. While these values are calculated using the best data available, it is possible that a local condition such as low permeability or a tendency to cone water or gas may prevent a well from being able to produce efficiently at its MPR. The unused portion of such a well's MPR cannot be trans-

ferred to another well. In addition to this, the production allowables may be subjected to penalty factors if excess volumes of gas or water are produced and not re-injected. The combination of these two factors can have a significant effect on the productivity of a reservoir. The Oil and Gas Conservation Board of Alberta regularly makes estimates of the Provincial productivity. We are informed that this averaged 756,000 barrels per day during 1957.

The following tabulation gives the average 1957 production rate and productivity for each of the four western provinces.

Province	Average Production Rate-barrels/day	Average Productivity barrels/day
British Columbia	1,000	1,200
Alberta	376,000	756,000
Saskatchewan	101,000	125,000
Manitoba	16,700	17,000
TOTALS	494,700	899,200

These figures show that the average Western Canadian productivity was 899,200 barrels per day during 1957. The average production rate of 494,700 barrels per day was equivalent to 55 percent of capacity. Considering Alberta alone, the tabulation indicates that the average production rate of 376,000 barrels per day was 50 percent of capacity.

Is this
Peak - maximum
Water flows pipe line ?

RECOVERY METHODS.

The oil reserve figures quoted above were calculated using recovery efficiencies based on present methods of depleting reservoirs. The amount of oil which will be recovered from a pool is a function of many things among which are the characteristics of the reservoir rock, the characteristics of the crude oil, and the type and magnitude of natural or induced forces acting within the system. With regard to this last point, it has been discovered during the past 25 years that the recovery efficiency can often be increased by injecting fluids into a reservoir system. Several of these methods are being used in Canada at this time. In addition to these well known and tested methods, there are several new approaches to increasing recovery that are still in the experimental stage. Therefore, any discussion of recovery methods may be logically broken into three parts; namely, primary recovery methods, present methods for increasing recovery, and new methods for increasing recovery.

These sections will deal only with oil and not natural gas since there are no techniques employed to increase the excellent recovery efficiencies that may be attained by properly using the natural forces within a gas reservoir.

Primary Recovery Methods.

The first step in producing oil requires that the reservoir fluid be moved from its place in the porous rock to the well bore where it can be taken to the surface. This movement can only be accomplished by an expenditure of energy. Three major natural sources of energy exist.

They are expansion of a water -filled zone or aquifer, expansion of a gas cap, and expansion of the reservoir oil and its dissolved gas. Under certain favourable circumstances, the force of gravity will have a significant influence. The recovery of oil from a reservoir is a function of the reservoir rock and fluid characteristics but is governed primarily by the nature of the available energy and the manner in which it is employed during depletion.

When the major source of energy is derived from expansion of gas which was originally dissolved in the reservoir oil, the production mechanism is termed Solution GasDrive. This is the least efficient depletion method and recovery will vary from only a few percent in the worst cases to approximately 30 percent under ideal conditions. The average recovery efficiency is generally considered to be 10 to 20 percent. If a large gas cap is in good communication with the oil reservoir, the production mechanism will be Gas Cap Drive. This is a better depletion method and recovery efficiency will vary from 25 to 75 percent depending on conditions and will average approximately 50 percent. The third major depletion mechanism is referred to as Water Drive. This will result when the oil reservoir is well connected to a large, permeable, water-filled zone. In this case also, recovery efficiency will vary from 25 to 75 percent and will average approximately 50 percent. The movement of fluids due to the force of gravity is seldom large enough to account for a major part of the driving energy. However, the presence of these forces in thick, permeable formations will often cause a significant modification of the naturally-occurring depletion mechanism. It very often happens that two or even all three natural drive mechanisms are operative in the same pool. When this occurs the depletion mechanism is said to be Combination Drive.

Examples of reservoirs whose major natural drive mechanism is Solution Gas Drive are Joffre Viking, Pembina and Steelman. There is no major field in Canada that relies solely on a natural Gas Cap Drive but reservoirs such as Bonnie Glen D3, Westerose D3, and many of the small Viking, Lower Cretaceous, and Mississippian pools draw a majority of their energy from gas caps. These may be more properly classified as Combination Drive reservoirs. Fenn-Big Valley, Redwater, and Ingoldsby are examples of pools being depleted primarily by strong water drives. The effects of gravity segregation will be quite beneficial in many of the large limestone reservoirs because of their large productive thicknesses and high permeabilities.

In Canada, recovery efficiencies that will be experienced from using only the natural driving forces will range from a minimum of only a few percent where very thin oil zones are encountered up to a maximum of approximately 70 percent in some thick, permeable limestone pools with Gas Cap and Water Drives assisted by gravity segregation. It is believed reasonable to estimate that the average recovery will be 30 to 35 percent of the oil in place.

Present Methods for Increasing Recovery

During recent years great progress has been made in the ability to analyse the behavior of a reservoir using mathematical or electronic techniques. This ability has led to a better understanding of the forces acting within a reservoir which has permitted accurate studies to be made showing how these forces may be employed to yield the optimum recovery of oil.

The obvious conclusion reached from early studies was that the introduction of energy from an external source might increase recovery. The first large-scale applications of this theory were carried out in fields that had reached total depletion mainly by Solution Gas Drive. Since these fields had already been depleted by primary recovery methods, the phrase "secondary recovery" was created to describe the new processes. As the ability to predict the destiny of any field improved, it became apparent that in most cases the injection of gas or water would create greater benefits if it took place before the point of primary depletion had been attained. In view of this improved approach, the term secondary recovery has lost much of its former universal popularity, and it is now common to refer to the processes as assisted recovery projects or injection projects.

The fields in Western Canada are comparatively young and no large pool has been completely depleted. Therefore, no large secondary recovery projects are in operation but there are many assisted recovery or injection projects.

These projects involve the injection of water or gas into the producing formation. The quantities injected may range from the return of the gas or water produced with the oil to the use of sufficient supplemental gas or water to maintain the reservoir pressure at a predetermined level or even to cause an increase to some higher level. An important factor in the initiation of a disposal program for returning produced gas or water to the producing formation may be the desirability of conserving the gas or preventing contamination by surface disposal of the salt water. In any case,

however, return of produced gas or water results in conservation of reservoir energy which would otherwise be dissipated. Conservation agencies in Western Canada recognize this problem by reducing the oil production allowables for wells that produce salt water or excess gas which is not re-injected. Penalties are waived when re-injection takes place. Most large fields with any significant water drive have water injection projects in operation. The largest is at Redwater where as much as 20,000 barrels of produced salt water are returned to the formation daily.

Gas or water from extraneous sources may also be injected to supplement the energy available in the reservoir. The location of the injection wells is dependent upon reservoir geometry and rock characteristics. In many cases these wells may be located on a five spot pattern in which injection and producing wells alternate. As the permeability of the formation increases, it is possible to have more producing wells per injection well, and either a nine spot pattern, or a line pattern is used. In the ideal case, gas will be injected entirely into the gas cap and water into the aquifer outside or below the oil productive portion of the reservoir.

Substantial portions of the Pembina Field are being subjected to a Five Spot Water Flood, and smaller areas are installing nine spot projects. A line flood is operating in the Joffre-Viking Pool. A pressure maintenance project involving the injection of water into the aquifer below the oil zone is in operation in the Leduc D-3 Pool, while pressure maintenance in the Golden Spike South D-3 Pool is being implemented by injection of gas into the gas cap.

The beneficial effects of these injection projects vary over a considerable range. Return of the produced water or gas is the least effective, resulting in increased recoveries of only a few per cent of the oil in place on the average. Full pressure maintenance may result in an increase in recovery of 30 percent of the oil in place, while the results of flooding operations will usually fall between these extremes. If all possible injection projects were undertaken, it is believed reasonable to estimate that the average recovery efficiency would be increased to about 45 percent of the original oil in place.

New Methods for Increasing Recovery.

The recovery methods discussed above, whether natural or induced, all rely on the ability of gas or water to flush oil to the well bore. The most efficient of these processes can yield recoveries as high as 75 percent with an average efficiency of approximately 45 percent. Recent papers in the literature indicate that many petroleum research laboratories are experimenting with entirely new concepts of increasing recovery. It is claimed that these methods may increase recovery from certain fields to almost 100 percent.

These new methods rely in part on the flushing ability of an injected fluid but a majority of the improvement is made possible by actually changing the characteristics of some of the crude oil while it is still in the reservoir. This change may be accomplished by adding large volumes of heat to the crude oil or by directly employing a light hydrocarbon such as propane to act as a solvent. The required volume of heat may be injected by employing hot gasses or it may be generated by actually burning some of

the crude oil while it is still in the reservoir. This latter approach, called in situ combustion, requires the injection of air so that combustion can be maintained. Fundamentally theprocess relies on the heat to lower the viscosity of the crude oil so that it may be flushed more readily. The heat will also distill some of the lighter hydrocarbons from the oil which in turn will establish a solvent bank. The heavy ends left behind will act as fuel for the burning process.

The second approach is generally referred to as Solvent Extraction or Miscible Displacement. This involves driving a bank of light hydrocarbons through an oil reservoir by means of fluid injection. In some cases it is possible to inject liquid propane and propel this with natural gas at high pressure. In other cases, it is possible to create the solvent bank by injecting high-pressure natural gas containing significant quantities of light hydrocarbons.

Since no large-scale projects have yet been attempted, it is not possible to even estimate what the ultimate effect of these processes will be. However, their potential value is very large when it is considered that approximately 55 percent of all the oil discovered in Canada will not be produced by presently known and tested recovery methods.

From the previous discussion it is apparent that the portion of oil within a reservoir that will not be recovered by primary production methods will vary from a minimum of 25 percent under favourable circumstances to a maximum of 90 percent or more where conditions are very unfavourable.

The volumes of oil represented by these figures are quite large for many reservoirs and assume immense proportions for the country as a whole. It has been estimated that the volume of recoverable oil which will ultimately be discovered in Western Canada will be approximately 50 billion barrels. These figures were obtained by using published data based on experience in the United States. Since the average recovery efficiency presently being experienced is considered to be approximately 30 to 35 percent, it follows that the total amount of oil in place which will be found in Western Canada will probably be about 150 billion barrels.

GAS PROCESSING

The purpose of the discussion which follows is not to present the detailed technical aspects of gas processing operations -- rather, it is intended to provide general information relating to the over-all functions of natural gas processing plants, to furnish statistical information relating thereto; and to provide an insight to some of the factors which govern or influence the installation and operation of such facilities.

GAS PROCESSING PLANTS

Casinghead gas, produced in conjunction with crude oil, as well as unassociated natural gas produced from gas fields, contains in its natural state varying amounts of water vapor, hydrocarbons which are extractable as liquids,and often times other objectionable impurities such as hydrogen sulphide, carbon dioxide, etc. Unlike crude oil, gas as produced in its natural state, normally is not suitable for pipeline transmission over long distances. Since pipelines afford the only economically feasible means of transporting natural gas,the gas must be subjected to treating processes to remove these objectionable substances so as to yield "dry" and "clean" residue gas which conforms to rigid specifications limiting the maximum tolerable content of such substances. This treatment, which constitutes the most common function of gas processing plants is, of necessity, performed at or near the point of production of the gas.

While the above-mentioned substances cannot be tolerated in gas which is to be transported and marketed as fuel, certain of these constituents upon further processing in a plant, yield valuable "by-products".

Generally speaking, the so-called "by-products" most commonly available as saleable products from gas processing plants are commercial propane, commercial mixed butanes (iso-butane and normal butane) mixtures

of propane and butanes (all of which are commonly referred to as liquefied petroleum gases or LPG's) and natural gasoline. In some instances, however, liquid or gaseous ethane as well as liquid iso-butane are available as plant products. In addition, in those instances where the produced gas contains significant quantities of hydrogen sulphide, elemental sulphur is often derived therefrom as a saleable plant product.

Significant technological advances have been made relative to methods of processing gas for liquid recovery during the past 20 to 30 years. The two processes used most widely today by the industry are the "absorption process" and the "refrigeration process".

The absorption process entails intimately contacting the natural gas at elevated pressures with low-boiling range oil (called absorption oil) which absorbs certain of the liquid constituents of the gas. The enriched oil stream is then heated and stripped of the absorbed liquids. The unstabilized liquid hydrocarbon mixture recovered thereby is then further processed by fractionation to effect the separation of the mixture into its various saleable components -- propane, butanes and natural gasoline.

The refrigeration process entails cooling the natural gas at elevated pressures by means of a refrigerant such as propane or ammonia to a low temperature in the range of minus 10° F. At these conditions certain of the liquid constituents of the gas are separated as an unstabilized liquid hydrocarbon mixture. Through fractionation, the mixture is separated into its various saleable components.

While higher percentage recoveries of ethane, propane and butanes can usually be realized through application of the absorption process, both of the above-mentioned processes are relatively efficient. Generally speaking

it is not uncommon for plants utilizing either process to be designed to recover approximately 50 percent of the propane, 85 percent of the butanes and essentially 100 percent of the natural gasoline constituents as contained in the "raw" natural gas.

Several different processes have been employed over the years in the treating of "sour" natural gas to remove therefrom hydrogen sulphide and carbon dioxide (called "acid gases"). However, the process most widely used today by the industry entails intimately contacting the sour gas with an amine solution which has an affinity for these acid gases. The amine solution, after having removed the acid gases from the natural gas, is heated and stripped of same. The regenerated amine solution is then available for re-use in the process. This process removes essentially all of the acid gases from the natural gas.

The acid gases evolved by regenerating the amine solution are flared or, if economics justify, they are supplied to a sulphur recovery plant wherein through an oxidation process, elemental sulphur is derived from the hydrogen sulphide gas. In excess of 90 percent of available sulphur is thereby normally recovered as a plant product.

An operation termed "dehydration" is performed in gas processing plants for the purpose of removing water vapor contained in natural gas. The removal of such water vapor is necessary to prevent formation of hydrates or ice with consequent plugging of lines; to prevent accumulation of water in transmission lines which reduces capacity; and to prevent corrosion of equipment. Dehydration is also practiced on propane streams to prevent freeze-ups which would otherwise occur when propane is vaporized for use in homes or commercial installations.

There are many methods and combinations of methods which are capable of accomplishing dehydration. However, except in certain specialized services, the principal dehydration methods are (1) solid desiccant dehydration, which employs beds of a granular material that can be regenerated by driving off absorbed water at elevated temperatures, and (2) liquid dehydration, which involves circulating a concentrated solution of glycol over a contactor through which the gas is passed. The water absorbed by the liquid is removed by distillation in a separate regenerator column.

In many instances, it is necessary that natural gas be dehydrated even before it is introduced into a gas gathering system for delivery to a plant for processing. Even in such instances, it is often necessary, dependent upon the particular treating processes to which the gas is subjected in the plant, that the dehydration operation be repeated at the plant in order to obtain a "dry" residue gas which is suitable for delivery to a gas transmission pipe line.

While the foregoing description of the treating processes to which natural gas is subjected in gas processing plants has purposely been presented in simple terms, it should be recognized that the operations are quite complex and require the installation of a great variety of types of costly equipment. The natural gas to be handled in a gas processing plant must, of course, be gathered from the various points of production in the field and delivered to the plant. The extent of such gathering facilities is dictated by the particular circumstances -- the gathering system may involve installation of a few miles of pipe lines or several hundred miles of pipe lines ranging from small to large diameter pipe. The plant proper

normally includes such major facilities as gas compressors, large vessels, processing towers such as fractionators, product storage tanks, steam generating and distribution facilities, electrical generating and distribution facilities, heat exchangers, pumps and drivers, instruments and controls, buildings, laboratory facilities, etc.

Numerous factors are involved in the determination of the gas handling capacity which is to be provided in a particular gas processing plant. In this connection, it might be well to point out a basic factor which differs as between processing plants required for handling of casinghead gas and those required for handling natural gas produced from gas fields.

The production of casinghead gas from an oil field fluctuates from day to day and from month to month depending upon the amount of oil being produced from the field. That is to say, the production of casinghead gas cannot be controlled directly at any given time. In those instances where the installation of a casinghead gas processing plant is prompted primarily by conservation measures, the capacity of the plant is established so as to effectively conserve the gas contemplated to be produced, having due regard to projected oil producing rate from the field. Cbviously then, the economic attractiveness of such a processing plant is geared to the prevailing rates of production of the oil with which the gas is associated -- when the oil production is curtailed for prolonged periods the plant might well operate at a net loss since, for reasons beyond the control of the operator, the plant must operate at reduced capacity. In many instances, installation and operation of such a plant is, at best, a marginal financial proposition.

In the case of a processing plant handling gas produced from a gas field, the capacity which must be provided is usually dictated by the terms and provisions of the prevailing gas sales contract. Most gas sales contracts specify a "daily contract quantity" and include provisions whereunder the seller of the gas is obligated, upon request of the buyer, to supply daily quantities in excess of said daily contract quantity -- the maximum quantity normally being fixed at about 120 percent of the daily contract quantity. Consequently, capacity must be provided in the plant to meet this obligation even though under the most favourable marketing conditions the buyer of the gas normally is under no obligation to purchase annually more than about 90 percent of the daily contract quantity. In other words, even when the gas processing plant is supplying a high load-factor market, there normally is no assurance that, on an annual basis, the plant will operate at more than 75 percent of its design or rated capacity.

A gas processing plant required to be installed for the removal of liquids and hydrogen sulphide contained in gas produced from a gas field entails a large investment. Such a plant must be operated at a high load-factor, both from the standpoint of plant processing efficiency and that of financial return. A low load-factor involves large changes in plant throughout which necessitate frequent changes in the complex operating controls, resulting in abnormally high unit operating costs and reduced process efficiency. The matter of load-factor is particularly critical in those instances where a relatively small portion of the revenue derived by a plant is attributable to the recovered liquids and other products - due either to the relatively small quantities available or the limited market.

for such products. In such instances, the plant operator must, of necessity, rely heavily upon the revenue derived from the sale of residue gas to make his plant operation a profitable venture. Consequently, it is imperative that either the plant be connected to a high load-factor market outlet for its residue gas or require what might be considered a prohibitively high price for residue gas supplied to a low load-factor market. The preceding comment is particularly applicable to the situation which will undoubtedly prevail in the western provinces where large reserves of natural gas containing high concentrations of hydrogen sulphide are being encountered. The added investment required to provide necessary facilities for treating such gas merely serves to aggravate the situation.

At the present time, the only high load-factor market in sight is that offered by major pipeline projects, and, therefore, unless export of surplus gas is permitted, it is virtually certain that large reserves of gas, particularly wet or sour gas, will remain undeveloped - and the Canadian public will derive no benefits therefrom.

Only three gas processing plants, having a total rated capacity of 130 million cubic feet daily, were operating in Western Canada prior to 1950 -- these having been placed in operation during the mid-1930's to handle gas produced from theTurner Valley field. During the period 1949 - 57 some $35.8 million was invested in on-the-site gas processing plant facilities. Eleven gas processing plants of varying capacities have been placed in operation in Western Canada since 1950. The total rated capacity of all gas processing plants in 1957 was about 700 million cubic feet daily. Some 400 million cubic feet per day of this rated capacity is

attributable to three plants which are, or will be, supplying gas to the gas transmission lines installed by Westcoast Transmission and Trans-Canada Pipelines. Pertinent data relating to the gas processing plants operating in Western Canada are shown in Appendix II.

It is conservatively estimated that in excess of $100 million will be expended by gas producers during the next three to four years to provide necessary additional facilities to process the anticipated gas requirements of the projects presently authorized for Westcoast Transmission and Trans-Canada Pipelines. This amount is, of course, over and above the significantly larger amounts already spent, and yet to be spent, by the oil and gas industry in making the gas available through exploratory and drilling operations, and for installation of major gas transmission pipe lines. Construction of such facilities will provide employment for hundreds of workmen; and upon completion, operation of the facilities will provide direct permanent employment for several hundred other persons. In addition, equipment manufacturers, suppliers and service firms will derive significant benefits from such a tremendous program. Further, the availability of additional products which will be derived from processing of the gas will tend to stimulate the demand therefor, and should serve to attract new industry including petrochemicals. In short, the over-all economy of Canada will be enhanced through these specific developments -- and for similar expanded developments which will necessarily follow when additional sizeable market outlets are obtained for Canada's surplus natural gas reserves.

DIFFERENCE IN APPROACH TO TRANSMISSION OF GAS AND OIL AND THE REASONS THEREFORE

The principal differences in the transmission of gas and oil lie in the methods of transportation and nature of the markets.

Oil can be transported by pipe line, by water, by railway or by road and can be stored at either end,. Its ultimate market can be virtually anywhere in the world and it is sold in large quantities to a few purchaser refineries. It can be directed from one market to another as demand dictates.

Gas can only be transported by pipe line, and can at present only be stored in appreciable quantities in a porous underground formation. It is sold mainly to public utility companies at any point along the route who in turn distribute it to a large number of purchasers, who then rely upon it as a factor in their economy and daily life. Once the distributing system has been installed the supply must be maintained and kept in balance with the demand. It does not have the same flexibility of transportation as oil.

When a new oil field is discovered, the producer can immediately start shipping his oil to market by truck, and some revenue is obtained immediately. If the field develops sufficiently, a pipe line to market can subsequently be laid.

Before a gas line can be laid a retail market sufficient to warrant the expenditure must be established at one end, and reserves of gas sufficient to supply that market must be established at the other end. Enough wells to prove the required reserves must therefore be drilled and then shut in until the line is laid. Further in most cases, a plant must be erected to remove any liquifiable hydrocarbons, sulphur, water, or other impurities, which the raw gas may contain and bring the residue gas, thus conditioned, to specifications demanded by the purchaser.

Once a gas trunk line has captured a particular market, it usually holds that market until the reserves at its source are exhausted. Conversely, if a potential market is lost to gas from another source, there is usually little chance of breaking into that market, until the other source has declined to the point where it can no longer supply that market.

SUMMARY OF CANADIAN CRUDE OIL PIPE LINES

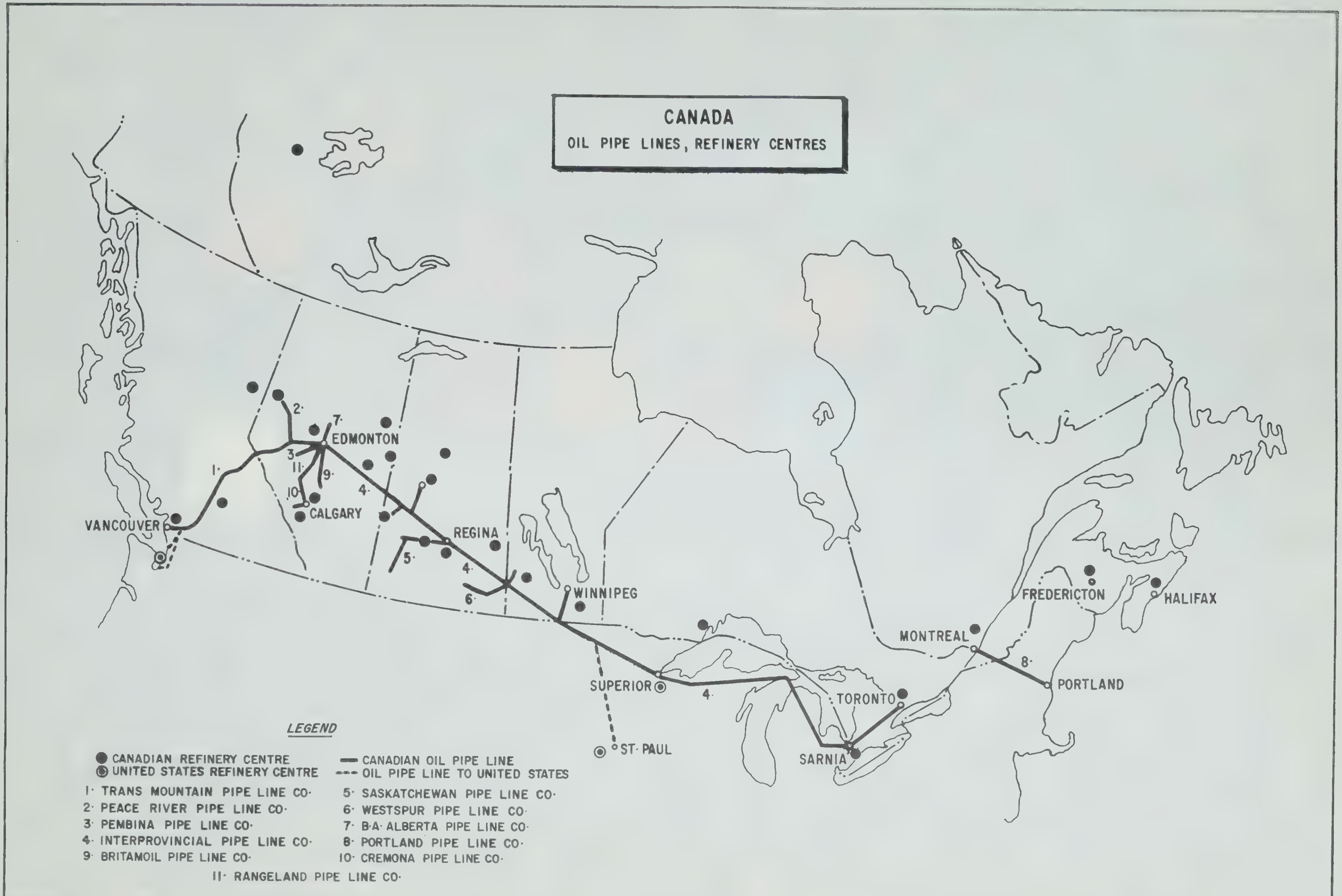
Company	Point of Origin	Destination	Length of Line (Miles) Gathering	Trunk	Size of Pipe	Source of Crude	Capacity of Line B/D Original	Present	1957 Throughput Barrels	Refineries/Pipelines Served	Tariff Rates	Remarks
Amurex Oil Company	Cessford field (Alberta)	Railhead at Cessford	-	5	6"	Cessford field	7,200	7,200	122,189		12¢	Initial cost $65,000
Anglo American Exploration Ltd.	Turner Valley field	Hartell, Alta.	$9\frac{1}{2}$	-	2" - 4"	Turner Valley	1,500	1,500	283,710	Anglo-American ref. Hartell, Alta.	-	
B-A Alberta Pipe Line Limited	Redwater field	Redwater terminal Interprovincial Pipeline	21.716		2" - 8"	Redwater	-	20,000	3,405,000	Interprovincial Pipeline	-	
B-A Saskatchewan Pipe Line Limited	Stony Beach, Sask.	Moose Jaw, Sask.	-	22.1	6-5/8" - 8-5/8"	Interprovincial Pipeline	-	22,000	4,450,000	British American Ref., Moose Jaw	-	
Britamoil Pipe Line Company Limited	West Drumheller field	Edmonton, Alta.	145	171.5	$3\frac{1}{2}$" - $12\frac{3}{4}$"	Duhamel, NewNorway, Malmo, Stettler, Fenn-Big Valley, Erskine, Clive, Joffre, West Drumheller fields	-	60,000	17,510,000	Interprovincial and Trans Mountain Pipelines	7¢ - 26¢	Extension to Drumheller field in 1958 - also lateral extensions to gathering system.
Edmonton Pipe Line Company Limited	Camrose, Alta.	Edmonton, Alta.	42.8	39.2	2", 3", 4", 6"	Joseph Lake, Armena, Camrose	16,000	16,000	4,251,629	Interprovincial and Trans Mountain pipelines; B-A & McColl-Frontenac Edm.refineries.	15¢ Joseph Lake; 16¢ Armena and Camrose	Initial cost $2,025,000. Additional gathering lines proposed for 1958.
Home Oil Company Limited - Cremona Pipeline Division.	Sundre field	Calgary, Alta.	10	63	$4\frac{1}{2}$", 6-5/8", 8-5/8".	Sundre, Westward Ho, Harmattan-Elkton fields.	18,000	18,000	2,267,810	Imperial Oil & B-A refineries, Calgary, Alta.	30¢	Initial cost $2,560,000. Extension of trunk line of 7 miles - 6-5/8" proposed for 1958.
Imperial Pipe Line Co. Ltd.	a) Leduc-Woodbend. b) Acheson and Golden Spike c) Excelsior-Fairydell d) Redwater	a) Interpr.Edm. terminal and I.O.L.refinery, Edm. b) Trans Mountain and Interp.Edm. terminal c) Interprovincial Excelsior term. d) Interprovincial Redwater term.	324.28	-	11.96 mi.2" 51.16 mi.3" 92.42 mi.4" 65.03 mi.6" 98.17 mi.8" 5.53 mi.12"	Leduc-Woodbend, Acheson, Golden Spike, Excelsior-Fairydell, Redwater		a) 72,000 b) 24,000 c) 6,000 d) 90,000	a) 18,472,535 b) 5,870,043 c) 1,316,732 d) 17,854,996	Interprovincial and Trans Mountain pipelines; I.O.L.refinery, Edmonton.	Leduc-Woodbend 7¢; Acheson 7¢; Golden Spike 7¢; Excelsior 6¢; Fairydell 24.5¢; Redwater 4¢.	Approx. 35 mi. of 8" loop was added to main gathering lines between 1951-54. Present gross capital assets $9.5 million.

Company	Point of Origin	Destination	Length of Line (Miles) Gathering	Trunk	Size of Pipe	Source of Crude	B/D Original	Present	Throughput Barrels	Refineries/Pipelines Served	Tariff Rates	Remarks
Interprovincial Pipe Line Co. and Lakehead Pipe Line Company Inc.	Redwater, Alta.	Port Credit, Ont.	-	1,931	427.8 mi.16" 363.1 mi.18" 438 mi.20" 657.9 mi.24" 247.6 mi.26" 644.4 mi.30" *2,778.8 mi. *(including loops)	Imperial & Britamoil pipelines at Redwater; Imperial & Pembina pipelines at Edm.;Gibson pipeline at Hardisty; Mid-Sask pipeline at Kerrobert; South Sask.pipeline at Regina; Westspur & Trans-Prairie pipelines at Cromer	95,000	300,000	99,251,268	Regent - Port Credit B-A - Clarkson Can.Oil - Sarnia Imperial - Sarnia Bay Refining - Bay City Dow Chemical " West Branch - West Branch Lk.Superior -Superior Gt.Northern - St.Paul International - Wrenshall Northwestern -St.Paul North Star - Winnipeg Imperial - Winnipeg Anglo-Can. - Brandon Imperial - Regina Cons.Co-op. - Regina B-A - Moose Jaw Royalite - Saskatoon	Redwater to Sarnia 64¢	The line has approximately 848 miles of loops. Construction is proposed to increase capacity of the system to approx.: 275,000 b/d out of Edmonton 379,000 b/d out of Cromer 261,000 b/d out of Superior at a cost of $10,000,000
Key Pipe Line Co. Ltd.	Lsd.1, Sec.4, Twp.15, Rge.1 W2.	Ptn.NW¼ Sec.27, Twp.15, Rge.1, W2.	1.17	5.03	3",4",8"	Wapella Field, Sask.	1,726	1,726	247,573		12.5¢	Initial cost $163,513
Mid-Saskatchewan Pipelines Limited	Smiley & Eureka fields in Sask.	Kerrobert, Sask.	15	33	4",6",8"	Smiley-Dewar and Eureka fields in Sask.	8,000	10,000	1,812,000	Interprovincial Pipeline	Smiley-Dewar 29¢ Eureka 26¢	Original Cost $1,000,000
Montreal Pipe Line Co. Ltd.	South Portland, Maine	Montreal, Quebec.	-	75.84 (2 lines)	12" - 18" (22"looping)	Foreign Countries	60,000	223,100	81,428,930	I.O.L., McColl-Frontenac, Shell, B-A, Canadian Petrofina refineries.	3¢	Initial cost $10,933,927 Approx.5.6 mi.22" looping installed in 1956. Additional 11 mi. of 22" loop planned for 1958. Ultimate capacity of line 270,000 b/d.
Peace River Oil Pipe Line Co.Ltd.	Sturgeon Lake field, Alta.	Edson, Alberta.	37.7	107	4½" - 16"	Sturgeon Lk.So., Sturgeon Lk. & Little Smoky fields.	-	55,000	3,392,672	Trans Mountain Pipeline	25¢	Proposed lateral extensions to gathering system in 1958.
Pembina Pipe Line Ltd.	Pembina field	Edmonton, Alta.	419.73	69.5	3",4",6", 8",10",12", 16".	Pembina, Keystone & Willesden-Green fields	125,000	155,000	38,285,000	Trans Mt. & Interpr. pipelines, I.O.L., B-A & McColl-Front. refineries in Edm.	Gathering Pembina & Keystone 7¢. Gathering Will-Green 12¢; Trunk 5¢	An addition of 50 - 60 miles of gathering system proposed in 1958.
Rangeland Pipe Line Company Limited	West Joffre	Rimbey, Alta.	84	56.7	4",6",8", 12"	Gilbey West, Gilbey, Bentley, West Joffre, Eckville, Medin, Garrington, Sundre, Innisfail fields	15,000	30,000	3,285,000	Texaco Pipeline at Rimbey, Alta.		Initial cost $5,344,600. Line's ultimate capacity 70,000 b/d.

Company	Point of Origin	Destination	Length of Line (Miles) Gathering	Trunk	Size of Pipe	Source of Crude	Capacity of Line B/D Original	Present	1957 Throughput Barrels	Refineries/Pipelines Served	Tariff Rates	Remarks
Saskatoon Pipe-Line Co. Ltd.	Milden, Sask.	Saskatoon, Sask.	-	56.9	6"	Interprovincial Pipe-line	6,000	6,000	1,304,246	Royalite Hi-Way Ref. at Saskatoon	N/A	Initial cost $1,587,068
South Saskatchewan Pipe Line Company	Cantuar, Sask.	Moose Jaw & Regina, Sask.	120	160	16" trunk	Fosterton, Success, Cantuar, Battrum, No. Premier, Gull Lk. Bone Cr., Instow & Dollard fields.	20,000	30,000	9,761,768	Husky & B-A Ref. at Moose Jaw; Consumers Coop. at Regina, Gt. Northern & Northwestern, St. Paul, Minn.	Gathering: 10¢ - 12½¢ Trunk: local 29.5¢ St. Paul 77¢	Ult. capacity 50,000b/d. Initial cost $12,000,000 Small extensions to gathering system and possibly a booster station proposed for '58.
Texaco Exploration Company, Pipe Line Department.	Rimbey, Alta.	Edmonton, Alta.	29	135	3", 4", 6", 8", 10", 12", 16"	Rangeland common stream & Gibson Petroleum common stream at Rimbey, Alta.; Westerose, Bonnie Glen, Wizard Lake & Glen Park fields.	42,000	106,000	18,966,703	Trans Mountain & Interprovincial pipelines. McColl-Frontenac & B-A refineries at Edm.	N/A	48 mi. 16" loop - 1953 5½ mi. 10" loop - 1957 Ultimate capacity of line 170,000 b/d.
Trans Mountain Oil Pipe Line Co.	Edmonton, Alta.	Burnaby, B.C. and Washington State.	-	787	24" & 30"	Alberta fields	120,000	250,000	56,535,215	Royalite, Ioco, Standard & Shell refineries in B.C.; General Petr. & Shell refineries in Washington	Edson to: Burnaby 45¢ Kamloops 43¢ Edmonton to: Burnaby 45¢ Kamloops 43¢ Pts. in Wash. 47¢	Two 50-mile 30" loops.
Trans-Prairie Pipelines Ltd. <u>Manitoba System:</u>	Daly field	Pumping station of Interprovincial at Cromer	-	105	3", 4", 6"	North Virden-Roselea, Virden-Roselea, East Cromer, Woodnorth & Daly fields.	15,000	23,000	6,010,946	Interprovincial Pipe-line	Daly 13¢ Virden-Roselea 11¢ Woodnorth & E. Cromer 25¢ Routledge 22¢	$150,000 will be spent in Manitoba during 1958.
<u>Saskatchewan System:</u>	Weyburn field	Westspur Pipe Line, Midale, Sask.	50½	-	4", 6", 8", 10"		-	40,000	2,729,335	Westspur Pipeline		$500,000 will be spent in this area during 1958.
Westspur Pipe Line Company/Producers Pipelines Ltd. (combined system)	Midale and surrounding fields through Steelman, Frobisher & Alida	Interprovincial Pipeline, Cromer.	252	185	4", 6", 8", 10", 12", 16"	Weyburn, Midale, Kingsford, Steelman, Frobisher, Alida, Nottingham, Ingoldsby, Cantal, Hastings, GlenEwen, Carnduff, Oxbow and South Manor fields.	55,000	90,000	20,140,000	Interprovincial Pipe Line, Cromer, Manitoba.	Midale 22½¢ Lampman 23¢ Steelman 17½¢ Frobish. 17½¢ GlenEwen 23¢ Ingoldsby 17½¢ Alida-Nottingham 14¢	Construction program for 1958 consists of approx. $3,500,000 for new gathering systems and $1,250,000 for new terminal facilities.
Winnipeg Pipe Line Company Limited	Gretna, Manitoba.	Greater Winnipeg area (East St. Paul & St. Boniface)	-	75.4	8", 10"	Fields in Man., Sask, & Alta. - also tankage of Interprovincial at Gretna, Man.	24,000	38/39,000	9,264,500	Imperial refinery, East St. Paul, Man. North Star ref., St. Boniface.	9¢	

SUMMARY OF CANADIAN PRODUCT PIPE LINES

Company	Point of Origin	Destination	Length of Line (Miles) Gathering	Trunk	Size of Pipe	Source of Products	Capacity of Line B/D Original	Present	1957 Throughput (Bbls.)	Markets Served	Tariff Rates	Remarks
;reen River Ex- loration Co.Ltd.	Bonnie Glen Gas Plant	Calmar Leading Rock	-	14.70	$4\frac{1}{2}$"	Bonnie Glen Gas Plant	5,720	5,720	231,843	Western provinces	$0.29155	Initial cost $400,195
'isku Products ipe Line Co.Ltd.	Devon, Alberta.	Edmonton, Alberta.	-	66.1	2" - 3"	Leduc Gas Conservation Plant No. 1	-	3,760	Propane 298,410 Butane 192,500 Pentane 123,160	LPG distributors, refineries and chemical plants in Edmonton area.	-	
arnia Products ipe Line	Sarnia, Ontario.	London, Hamilton, No.Toronto, Toronto, Ontario.	-	195.4	6-5/8", $10\frac{3}{4}$", $12\frac{3}{4}$"	Imperial Oil Refinery, Sarnia, Ont.	37,000	76,000	15,224,500	London, Hamilton, Toronto, Ontario.	-	45.4 miles looped. Initial cost $10,644,000.
un-Canadian ipe Line Company imited	Sarnia, Ontario.	Toronto, Ontario.	-	211	8"	Sun Oil Co.Ltd. & Canadian Oil Cos. refineries.	18,000	22,000	6,972,556	London, Hamilton and Toronto, Ont.	-	Ultimate capacity 35,000 b/d. Initial cost $6,107,455.
Trans-Northern Pipe Line Co.	Montreal, Quebec.	Toronto & Hamilton, Ont. (Lateral to Ottawa, Ont.)		442	N/A	Montreal refining area.	-	65,000	N/A	Ontario	-	Pipeline began operations Oct.1/52.
Valley Pipe Line Co. Ltd.	Turner Valley, Alta.	Calgary, Alta.	75.10	94.36	Gathering - 2" & 4" Trunk - 4" & 6"	Turner Valley field	24,000	24,000	1,767,521	Calgary & Royalties	16¢	

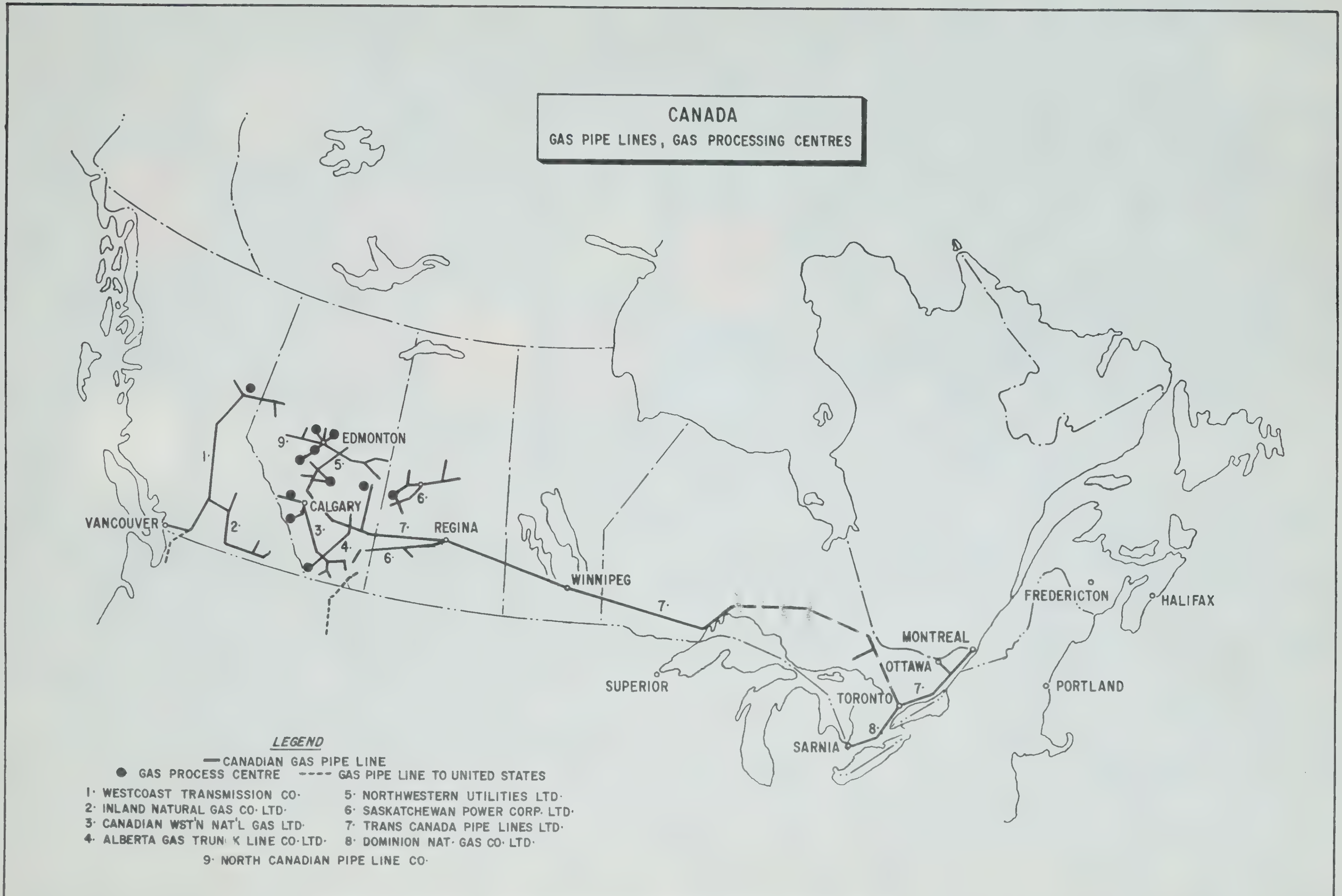

CANADA
OIL PIPE LINES, REFINERY CENTRES
VANCOUVER
EDMONTON
CALGARY
REGINA
WINNIPEG
SUPERIOR
ST. PAUL
SARNIA
TORONTO
MONTREAL
PORTLAND
FREDERICTON
HALIFAX
LEGEND
CANADIAN REFINERY CENTRE
UNITED STATES REFINERY CENTRE
CANADIAN OIL PIPE LINE
OIL PIPE LINE TO UNITED STATES
1. TRANS MOUNTAIN PIPE LINE CO.
2. PEACE RIVER PIPE LINE CO.
3. PEMBINA PIPE LINE CO.
4. INTERPROVINCIAL PIPE LINE CO.
5. SASKATCHEWAN PIPE LINE CO.
6. WESTSPUR PIPE LINE CO.
7. B.A. ALBERTA PIPE LINE CO.
8. PORTLAND PIPE LINE CO.
9. BRITAMOIL PIPE LINE CO.
10. CREMONA PIPE LINE CO.
11. RANGELAND PIPE LINE CO.

SUMMARY OF CANADIAN NATURAL GAS PIPE LINES

Company	Point of Origin	Destination	Length of Line (Miles) Gathering	Trunk	Size of Pipe	Source of Gas	Capacity of Line (MCF) Present	Ultimate	1957 Throughput (MCF)	Markets Served	Tariff Rates (per MCF)	Remarks
Ajax Alberta Pipeline Limited	Morinville, Alberta.	Edmonton, Alberta.		52*	3", 4", 6", 8", 10".	Morinville and St. Albert gas fields	60,000	-	8,088,000	Canadian Chemical Co.Ltd., Edmonton; Plains Western Gas & Electric Co., Morinville, Alta.	-	Initial cost $2,000,000
The Alberta Gas Trunk Line Company Limited	Gathering agent in the province of Alberta for Trans-Canada Pipe Lines Limited		-	117	18" & 34"	Present source - Provost, No.Bindloss & So.Bindloss fields	125,000	-	2,800,000	Trans-Canada Pipeline.	-	Line commenced operation July/57. Pincher Cr.&Cessford fields to be linked in'58.
Canadian-Montana Pipe Line Company	Pendant D'Oreille, Alberta.	Alberta-Montana border	-	18	16"	Pendant D'Oreille, Smith Coulee, Manyberries, Black Butte and Comrey fields	65,000	98,500	10,825,609	Montana Power Co. markets in Montana	-	Initial cost $767,000.
Canadian Western Natural Gas Co. Ltd.	Line runs throughout southern Alberta		23.8	620.7	$1\frac{1}{4}$" to 16"	Brooks, Bow Island, Foremost, Fenn-Big Valley-Stettler (gathered at Nevis), Jumping Pound & Turner Valley	250,000	-	37,709,884	Calgary, Lethbridge & 49 other communities in southern Alberta.	-	Initial cost $10,600,000 57 mi.16"transmission line Carbon field to Calgary & 31 mi.3" transmission line to serve additional communities proposed for 1958.
Grande Prairie Transmission Co. Ltd.	Rycroft and Hamlin Creek fields.	Grande Prairie, Alberta		70*	$4\frac{1}{2}$"	Rycroft & Hamlin Creek fields.	6,500	-	N/A	Spirit River, Rycroft, Woking, Sexsmith, Clairmont & Grande Prairie.	-	Initial cost $750,000
Inland Natural Gas Co. Ltd.	Savona, B.C.	Nelson, B.C.	80	304	6", 8", 10", 12"	Westcoast Transmission line	50,000	-		Interior of British Columbia	-	Commenced operation Nov.1/57. Initial cost $24,000,000.
Mid-Western Industrial Pipelines Ltd.	Fort Saskatchewan field	Sherritt-Gordon Mines Limited, Ft.Sask.	9	1.4	Gath.3", 4", 6"; Trunk 8"	Fort Saskatchewan field.	6,000	20,000	1,849,692	Sherritt-Gordon Mines Limited	3¢	Initial cost $370,000
Mid-Western Industrial Pipelines (Redwater) Ltd.	Redwater, Alta.	Sherritt-Gordon Mines Limited, Ft.Sask.	-	18.5	6-5/8"	Imperial Oil Absorption Plant, Redwater, Alta.	3,000	6,500	1,257,000	Sherritt-Gordon Mines Limited	3.257¢	Initial cost $380,000
Mid-Western Industrial Pipelines (Wabamun) Ltd.	Alexander Indian Reserve	Wabamun, Alberta.	4	34	Gath.6-5/8" Trunk $10\frac{3}{4}$"	Alexander Indian Reserve	25,000	100,000	6,778,175	Calgary Power Steam Power Plant, Wabamun, & North Canadian Oils for delivery to Hinton, Alta.	2.4¢	Initial cost $1,300,000

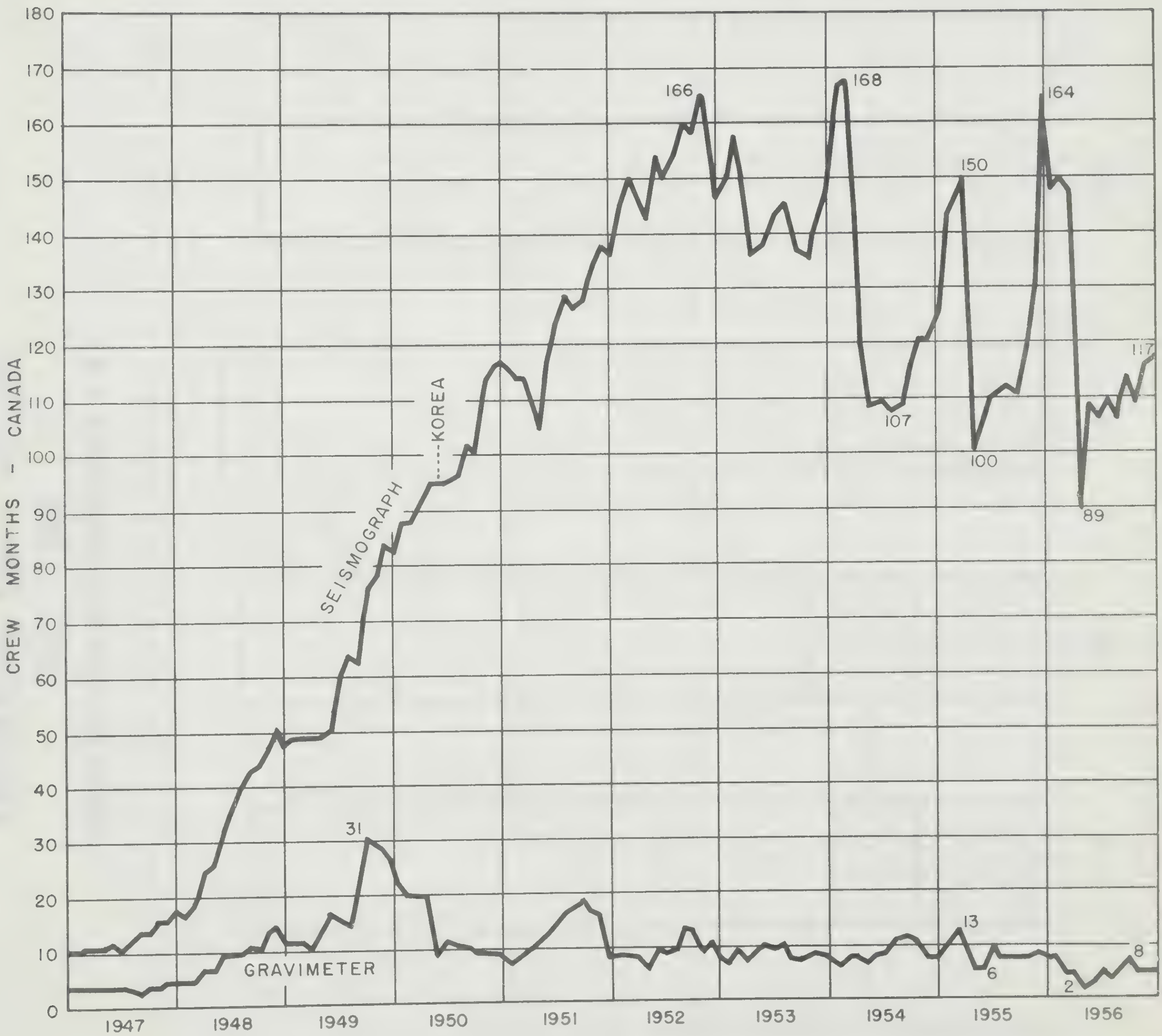
Company	Point of Origin	Destination	Length of Line (Miles) Gathering	Trunk	Size of Pipe	Source of Gas	Capacity of Line (MCF) Present	Ultimate	1957 Throughput (MCF)	Markets Served	Tariff Rates (per MCF)	Remarks
North Canadian Oil Limited Pipeline	Wabamun, Alta.	Hinton, Alta.		136.6	10"	Mid-Western Industrial Pipelines (Wabamun) Ltd.	9,000	70,000	1,471,118	Northwestern Pulp & Power Ltd., Hinton, Trans Mountain Pump Stn., Edson, Alta. - towns along route of line.	N/A	Initial cost $5,000,000
Northwestern Utilities Limited	North-Central Alberta	North-Central Alberta	243	778	$1\frac{1}{4}$" - 20"	Fields in North-Central Alberta	341,000	-	47,476,978	North-Central Alta. Distribution to communities	-	71 miles 16" pipeline from Pembina to Edmonton proposed for 1958.
Peace River Transmission Company	Pouce Coupe field	Dawson Creek, B.C.		28*	$4\frac{1}{2}$"	Pouce Coupe and South Coupe fields in Alberta.	6,000	-	N/A	Dawson Creek and Pouce Coupe, B.C.		Initial cost $300,000
Saskatchewan Power Corporation	Coleville, Brock and Success fields	Swift Current, Moose Jaw, Humboldt, Saskatoon, Prince Albert-North Battleford, Saskatchewan.	72.8	673.8	$2\frac{1}{2}$" to 14"	Coleville-Hoosier, Brock, Success & So.Success fields	90,000	130,000	11,033,147	Saskatoon, Prince Albert, No.Battleford, Swift Current, Moose Jaw, Regina & 29 smaller centers in Sask.	-	280 miles transmission lines proposed for 1958.
South Alberta Pipe Lines Ltd.	Etzikom gas field	Medicine Hat, Alberta.	9.34	44.95	Gath. $4\frac{1}{2}$" & 6-5/8" Trunk $10\frac{3}{4}$"	Etzikom gas field	19,500	19,500	3,285,366	Northwest Nitro-Chemicals Ltd., & City of Medicine Hat	-	Initial cost $1,650,000
Trans-Canada Pipe Lines Limited (Line 60% completed at year-end 1957)	Burstall, Sask.	Montreal, Quebec.		2,294	20", 30", 34"	Bindloss, Provost, Sibbald, Oyen, Cessford, Princess-Patricia, Atlee-Buffalo, Pincher Creek, Nevis, Countess-Duchess, Kessler, Homeglen-Rimbey, Gilby fields	620,000	-	-	Local utility companies in Saskatchewan, Manitoba, Ontario and Quebec.	-	Initial cost $378,000,000. 1958 construction will include 735 miles of 30" line from Port Arthur to Toronto.
Westcoast Transmission Company Limited	Taylor, B.C.	Sumas (on the Internatiol border between Canada & United States)	155	650	30"	Ft.St.John, S.E.Ft. St.John, Montney, Stoddard, Buick Creek, Red Creek, Parkland fields in B.C.; Pouce Coupe, So.Pouce Coupe & Gordondale fields in Alberta.	400,000	660,000		British Columbia and Northwestern States.	-	Initial cost $175,000,000. Commenced operation October, 1957.

* (Includes Gathering)

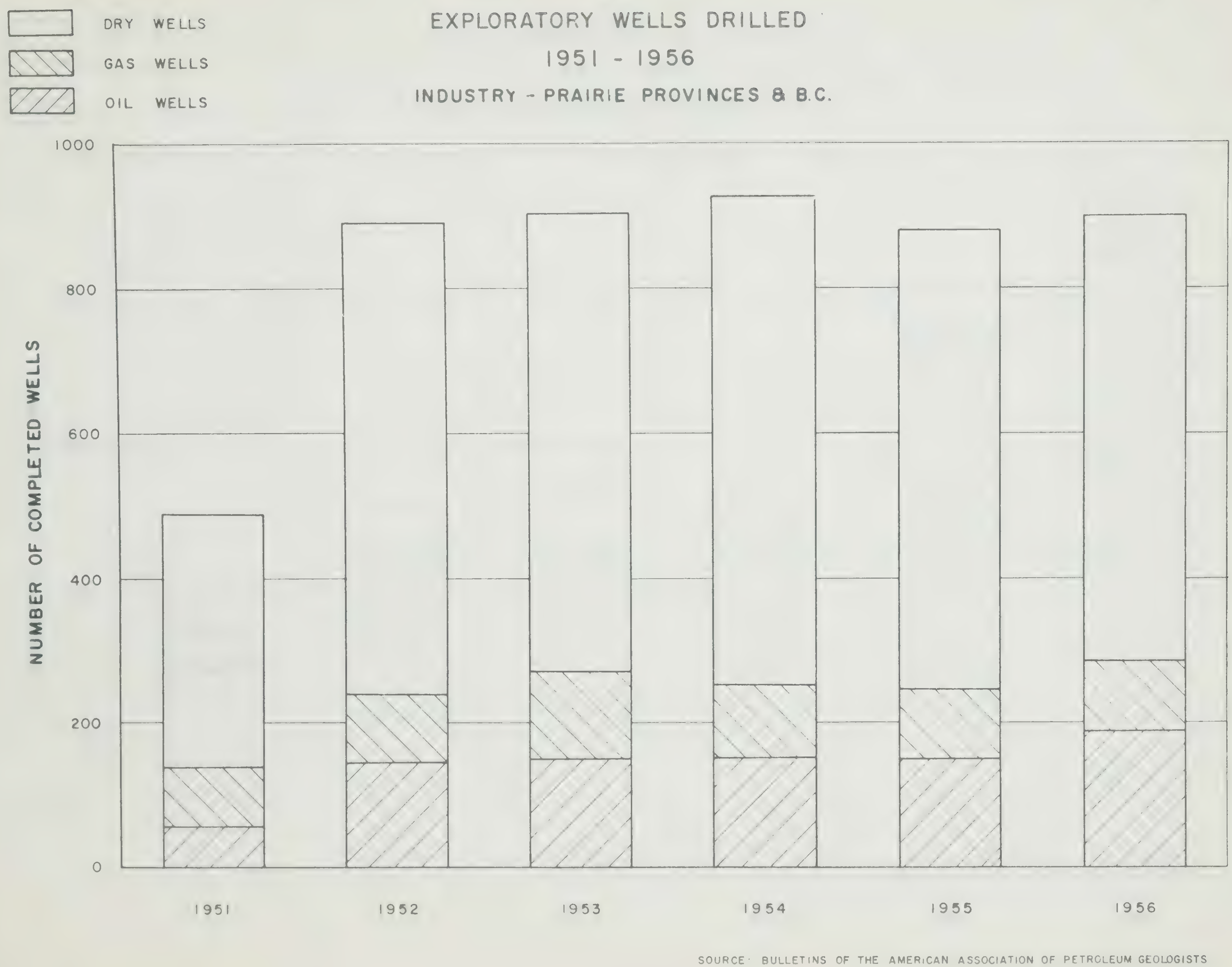


CANADA
GAS PIPE LINES, GAS PROCESSING CENTRES
VANCOUVER
EDMONTON
CALGARY
REGINA
WINNIPEG
SUPERIOR
TORONTO
OTTAWA
MONTREAL
SARNIA
FREDERICTON
HALIFAX
PORTLAND
LEGEND
CANADIAN GAS PIPE LINE
GAS PROCESS CENTRE
GAS PIPE LINE TO UNITED STATES
1· WESTCOAST TRANSMISSION CO·
2· INLAND NATURAL GAS CO· LTD·
3· CANADIAN WST'N NAT'L GAS LTD·
4· ALBERTA GAS TRUNK LINE CO·LTD·
5· NORTHWESTERN UTILITIES LTD·
6· SASKATCHEWAN POWER CORP· LTD·
7· TRANS CANADA PIPE LINES LTD·
8· DOMINION NAT· GAS CO· LTD·
9· NORTH CANADIAN PIPE LINE CO·

GEOPHYSICAL OPERATIONS IN CANADA



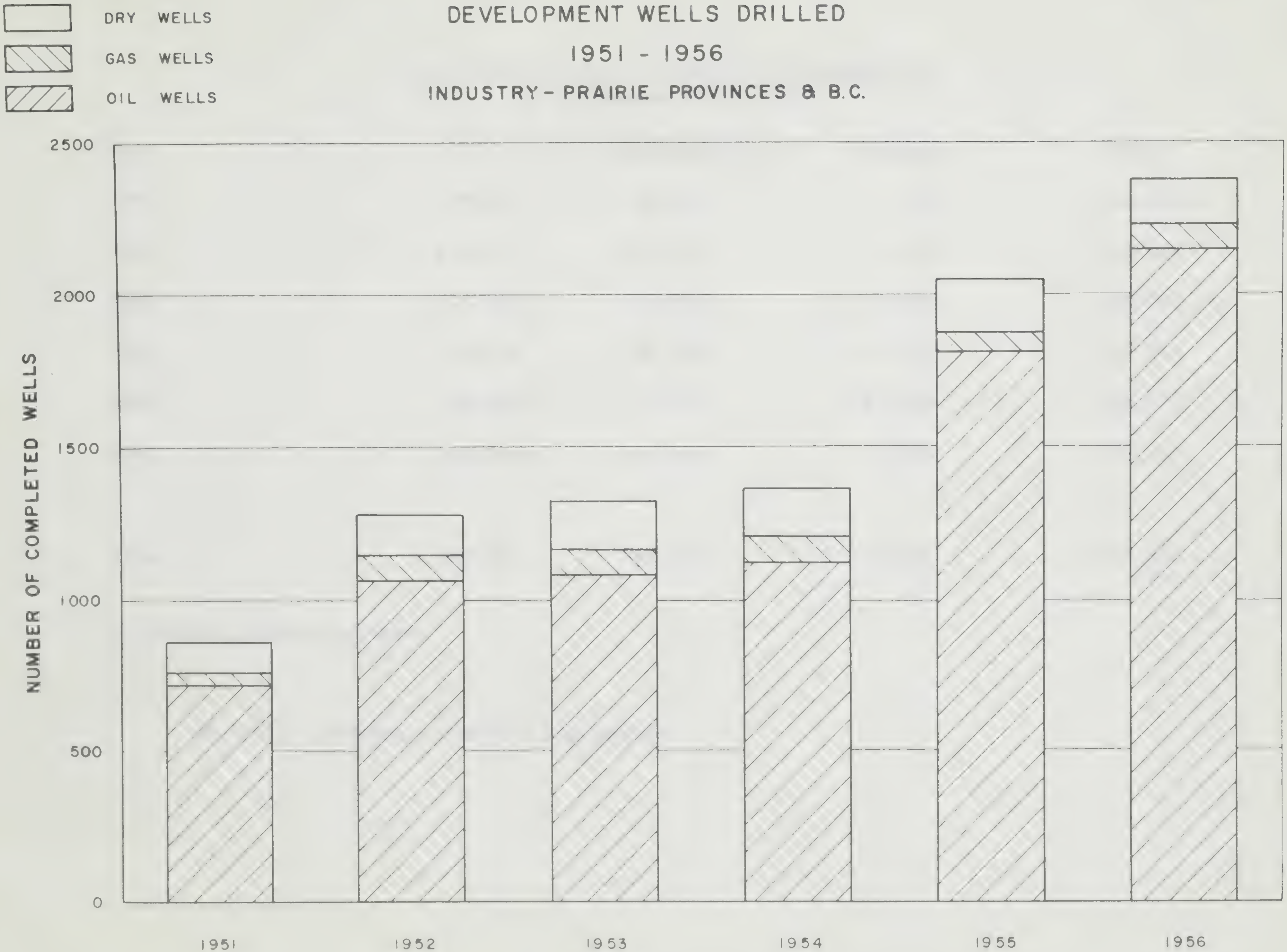
Source : Society of Exploration Geophyicists


DRY WELLS
GAS WELLS
OIL WELLS
EXPLORATORY WELLS DRILLED
1951 - 1956
INDUSTRY - PRAIRIE PROVINCES & B.C.
NUMBER OF COMPLETED WELLS
1000
800
600
400
200
0
1951
1952
1953
1954
1955
1956
SOURCE: BULLETINS OF THE AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS

DEVELOPMENT WELLS DRILLED

1951 - 1956

INDUSTRY - PRAIRIE PROVINCES & B.C.



SOURCE . CANADIAN OIL AND GAS INDUSTRIES

GROSS ADDITIONS TO CRUDE OIL RESERVES
(In Thousands of Barrels)

Year	Alberta	Saskatchewan	Manitoba	Total
1951	208,800	12,000	500	221,300
1952	256,756	104,947	1,725	363,428
1953	174,925	60,710	9,440	245,075
1954	391,368	45,505	20,370	457,243
1955	352,840*	25,543	20,282	398,665
1956	363,934*	142,105	2,633	508,672
Total	1,748,623	390,810	54,950	2,194,383

* Includes British Columbia

SOURCE: Canadian Petroleum Association.

WESTERN CANADIAN NATURAL GAS RESERVES

ESTIMATED RESERVES ATTRIBUTED TO DISCOVERIES 1951 -1956

	Trillion Cu. Ft.
Alberta (1)	10.0
Saskatchewan (2)	.5
British Columbia (3)	1.2
Total	11.7

Gas/Oil equivalent at 30 Mcf = 1 bbl. - 390,000,000 barrels.

(1) The Oil and Gas Conservation Board of Alberta estimates reserves added by new discoveries December 31st, 1950 to September 30th, 1956 at 9.62 trillion cu. ft.

(2) Saskatchewan reserves estimated from proven recoverable reserves as at December 31st , 1956 of 548 billion cu. ft. with an allowance being made for reserves discovered prior to 1951. Source: Saskatchewan Department of Mineral Resources.

(3) Estimated

WESTERN CANADA

RESERVES AND PRODUCTION OF CRUDE OIL

(In Thousands of Barrels)

Year	Proved Remaining Reserves as at December 31st.	Production	Life Index Years	Percentage Withdrawal
1950	1,202,600	28,378	42.4	2.36
1951	1,376,660	47,402	29.0	3.44
1952	1,679,539	61,037	27.5	3.63
1953	1,843,987	80,580	22.9	4.37
1954	2,206,143	95,576	23.1	4.33
1955	2,505,775	128,903	19.4	5.14
1956	2,845,734	171,371	16.6	6.02
1957	2,860,599	181,401	15.8	6.34

SOURCE: Canadian Petroleum Association

PRODUCTION OF CRUDE OIL
In Thousands of Barrels

	1951	1952	1953	1954	1955	1956	1957*	Cumulative 1951-1957
Alberta	45,915	58,919	76,816	87,637	113,035	143,910	137,805	664,037
Saskatchewan	1,247	1,697	2,791	5,423	11,317	21,077	36,777	80,329
Manitoba	12	107	656	2,148	4,146	5,787	6,106	18,962
British Columbia	-	-	-	-	-	148	353	501
Total	47,174	60,723	80,263	95,208	128,498	170,922	181,041	763,829

VALUE OF CRUDE OIL TO PRODUCERS
In Thousands of Dollars

	1951	1952	1953	1954	1955	1956	1957*	Cumulative 1951-1957
Alberta	115,809	139,658	193,118	227,878	274,246	355,174	358,541	1,664,424
Saskatchewan	1,460	2,046	3,483	7,637	17,480	34,943	78,515	145,564
Manitoba	25	182	1,658	5,566	9,517	13,417	14,960	45,325
British Columbia	-	-	-	-	-	296*	706	1,002
Total	117,294	141,886	198,259	241,081	301,243	403,830	452,722	1,856,315

* Estimated

SOURCE: Alberta Oil and Gas Conservation Board, Saskatchewan Department of Mineral Resources, Manitoba Department of Mines and Natural Resources, British Columbia Department of Mines.

NATURAL GAS DELIVERIES TO GAS GATHERING SYSTEMS

Quantities in MMcf.

	1951	1952	1953	1954	1955	1956	Cumulative 1951-1956
Alberta	67,849	76,695	86,501	103,189	129,256	139,655	603,145
Saskatchewan	859	1,131	1,549	3,068	6,062	8,785	21,454
Total	68,708	77,826	88,050	106,257	135,318	148,440	624,599

VALUE OF NATURAL GAS TO PRODUCERS

In Thousands of Dollars

	1951	1952	1953	1954	1955	1956	Cumulative 1951-1956
Alberta (1)	5,292	5,979	6,747	8,038	9,976	10,960	46,992
Saskatchewan	85	119	162	310	561	806	2,043
Total	5,377	6,098	6,909	8,348	10,537	11,766	49,035

(1) The value of natural gas in Alberta for the years 1954, 1955 and 1956 has been taken from surveys of the "Natural Gas Industry in Canada during 1955, and 1956." Previous years have been estimated from the average value computed for years 1954 - 1956.

SOURCES: Alberta Oil and Gas Conservation Board.
Saskatchewan Department of Mineral Resources.
Department of Mines and Technical Surveys, Mineral Resources Division, Ottawa.

EXPENDITURE ON PETROLEUM DEVELOPMENT
IN SASKATCHEWAN 1951 - 1957.
(In Thousands of Dollars)

Item	1951	1952	1953	1954	1955	1956	1957
Development Wells	N.A.	N.A.	16,094	14,921	27,474	42,600	56,917
Wildcat Wells	N.A.	N.A.	12,510	13,101	12,275	17,700	13,369
Core & Structure Tests	N.A.	N.A.	557	2,039	698	500	505
SeismicSurvey	N.A.	N.A.	6,128	5,009	5,011	4,900	7,408
Other Geophysical	N.A.	N.A.	734	588	809	900	335
Other Exploration Expenditures	N.A.	N.A.	7,892	12,640	11,168	30,100	55,027
Sub Total	N.A.	N.A.	43,915	48,298	57,435	96,700	133,561
Pipelines	N.A.	N.A.	7,895	27,529	16,490	52,000	35,557
Refineries	N.A.	N.A.	8,000	10,592	8,198	6,000	6,065
Sub Total	N.A.	N.A.	15,895	38,121	24,688	58,000	41,622
Grand Total	18,000	31,000	59,810	86,419	82,123	154,700	175,183

Source: Saskatchewan Department of Mineral Resources.

PETROLEUM AND NATURAL GAS INDUSTRY EXPENDITURES

BRITISH COLUMBIA

In Thousands of Dollars

	1950	1951	1952	1953	1954	1955	1956	1957
Land Acquisition and Rental (1)	N.A.	N.A.	N.A.	47	2	2,279	1,398	102
Geological	87	352	392	380	748	25	168	462
Geophysical	--	369	1,326	3,794	5,905	3,032	7,507	8,338
Drilling	914	1,661	2,992	7,175	4,899	5,256	7,788	11,086
Total	1,001	2,382	4,710	11,396	11,554	10,592	16,861	19,988

(1) By fiscal year

Source: British Columbia Department of Mines.

TOTAL EXPENDITURES OF FIRMS ENGAGED IN THE PETROLEUM INDUSTRY OF ALBERTA
OIL FIRMS PROPER 1951 - 1956.

(In Thousands of Dollars)

	1951	1952	1953	1954	1955	1956
Number of Firms	N.A.	N.A.	341	278	254	195
ADMINISTRATION						See Following Table
General Costs	19,420 (1)	26,223 (1)	23,051	24,436	30,940	
Federal, Provincial, Municipal Tax excluding Income Tax			2,058	2,449	2,416	
Capital Expenditures			31,418	46,746	58,422	
Leases, Rentals, Royalties & Fees			65,073	95,668(4)	93,363(4)	
Surface Leases			2,081	3,462	1,337	
EXPLORATION	66,047(2)	93,100(2)	50,109	49,417	46,173	
DRILLING - OIL AND GAS	73,220(3)	94,818(3)				
Development			50,085	46,529	79,324	
Cutpost			5,901	1,834	4,043	
Wildcat			32,403	37,783	40,923	
OPERATION OF WELLS - Including Flow Lines & Related Facilities	21,428	30,391	19,623	20,736	38,720	
PIPELINES AND RELATED FACILITIES	1,976	3,839	3,671	1,437	3,983	
OTHER SERVICES	886	1,650	1,565	1,447	1,951	
GRAND TOTAL	182,977	250,021	287,038	331,944	401,595	493,540

SOURCE: Alberta Bureau of Statistics, Department of Industry & Labour.

(1) Reports only include Administration
(2) Assumed to include Land Expenditures but not royalty
(3) Breakdown not available
(4) Land Acquisition, Rental and Royalty incorrect. Provincial Government Reports, Purchase Rentals and Royalties of $108,921 in 1954 and $108,956 in 1955. A survey was conducted by the Provincial Bureau of Statistics in 1954 and it was found that $25,742 land costs were reported under capital expenditures, presumably this occurred in 1955 also.

TOTAL NET CASH EXPENDITURES OF OIL FIRMS (PROPER) ENGAGED IN THE DEVELOPMENT OF ALBERTA OIL RESOURCES - ALBERTA, 1956

(in Thousands of Dollars)

1. EXPLORATION	$
(a) Geological and Geophysical Expenditures	46,590
(b) Exploratory Drilling -	
Dry	32,125
Productive - Oil	11,528
Gas/Condensate	4,940
(c) Land Acquisition and Rentals	99,672
(d) Overhead (not included above)	10,223
2. DEVELOPMENT DRILLING -	
Dry	4,356
Productive - Oil	85,104
Gas/Condensate	3,000
Overhead (not included above)	2,406
3. CAPITAL EXPENDITURES -	
(a) Field Equipment	
Oil	27,841
Gas/Condensate	3,746
(b) Other	14,944
4. OPERATION OF WELLS - Including Flow Lines and Related Facilities	36,960
5. NATURAL GAS PLANTS -	20,902
6. GENERAL -	
(a) Taxes (excluding income tax)	3,574
(b) Royalties	50,443
(c) All other Expenses (not allocated in 1-5)	35,186
TOTAL CASH EXPENDITURES OF OIL FIRMS PROPER	493,540

SOURCE: Alberta Bureau of Statistics,
Department of Industries and Labour.

PETROLEUM REFINERIES in CANADA as of DECEMBER 31, 1957.

Location of Refinery	Company	Type of Refinery	Date of First Operation	Source of Crude	Crude Oil Capacity B/CD	Cracking Plant Units	Cracking Capacity B/CD	Other Units	Proposed for 1958
NOVA SCOTIA Halifax	Imperial Oil Ltd.	S.C.A.	1918	Venezuela	44,500	Catalytic - fluid	17,000		
NEW BRUNSWICK Weldon	New Brunswick Cil-fields Ltd.	S.	1931	New Brunswick	300				
QUEBEC Montreal East	The British American Oil Co.Ltd.	S.C.A.	1931	Venezuela	45,000	Catalytic - fluid	19,900	Cat.Poly. Cat.Reformer Cumene	
Pte.-aux-Trembles	Canadian Petrofina Limited	Comp.	1955	Middle East Venezuela	20,000	Catalytic - houdriflow Thermal - fluid coking	18,000	Alkylation, polymerization, ultraforming, desulphurization	Increase capacity to 30,000 b/d by addition of more distillation and reforming cap.
Montreal East	Imperial Oil Ltd.	S.C.A.	1916	Venezuela	71,800	Catalytic - fluid Thermal - visbreaking - reforming	19,500 12,000 4,200	Cat.Poly.	
Montreal East	McColl-Frontenac Cil Company	S.C.	1927	Middle East Trinidad	59,000	Catalytic - fluid Thermal - visbreaking	21,600 12,300	Cat.Poly. Cat.Reforming	10,000 b/d Hydrotreater, completion early 1958.

Location of Refinery	Company	Type of Refinery	Date of First Operation	Source of Crude	Crude Oil Capacity B/CD	Cracking Plant Units	Cracking Capacity B/CD	Other Units	Proposed for 1958
Montreal East	Shell Oil Company of Canada Ltd.	Comp.	1933	Venezuela Middle East	60,000	Catalytic - fluid Thermal - visbreaking	22,000 7,500	Cat. Reforming, Vac-flashing, Hydro-desulphurization, Cat. Poly.	
ONTARIO									
Clarkson	The British American Oil Co. Ltd.	Comp.	1943	Western Canada Venezuela	55,600	Catalytic - fluid Thermal - cracking	10,500 4,000	Cat. Poly. Lube Plant Grease Plant	
Corunna	Canadian Oil Companies Limited	S.C.	1952	Western Canada	30,000	Catalytic - fluid Thermal - visbreaking	12,000 4,000	Cat. Poly. Cat. Reforming	Engineering work on new 20,000 b/d crude unit.
Fort William	Canadian Husky Oil Ltd.	S.A.	1952	Southeastern Saskatchewan	4,000	Catalytic - reforming	1,000	Desulphurization	Dieselformer for hydrogenation of intermediate products - 1000 b/d. Comp. Feb/58. 120,000 bbls. additional storage.
Sarnia	Imperial Oil Ltd.	S.C.A.	1897	Alberta and Ontario	77,000	Catalytic - fluid Thermal - visbreaking - reforming	20,000 16,000		

Location of Refinery	Company	Type of Refinery	Date of First Operation	Source of Crude	Crude Oil Capacity B/CD	Cracking Plant Units	Cracking Capacity B/CD	Other Units	Proposed for 1958.
Port Credit	Regent Refining (Canada) Ltd.	S.C.	1938	Western Canada Trinidad Venezuela	20,000	Catalytic - fluid	7,000	Cat.Poly. Cat.Reforming	
Sarnia	Sun Oil Company Limited	S.C.	1953	U.S.Gulf Coast	15,000	Catalytic - houdriflow	11,000	Cat.Reforming	
MANITOBA Brandon	Anglo-Canadian Oils Limited	S.C.	1938	Alberta	3,000	Thermal - cracking	1,375	Cat.Poly. Cat.Reforming	1000 BSD Plat-former; 50 BSD Poly.Unit.
Winnipeg	Imperial Oil Ltd.	S.C.A.	1951	Alberta	18,000	Catalytic - fluid	6,000		Powerformer 3,150 B/CD.
St.Boniface	North Star Oil Limited	Comp.	1927	Western Canada	12,000	Catalytic - fluid	5,000	Vac.distillation Cat.Poly.	2700 b/d Cat. desulphurizing; 2700 b/d cat. reforming.
Winnipeg	Radio Oil Refin-eries Limited	S.	1930	Western Canada	2,000				
SASKATCHEWAN Moose Jaw	The British Amer-ican Oil Co.Ltd.	S.C.A.	1934	Alberta Saskatchewan	13,500	Catalytic - fluid Thermal - cracking - delayed coking	4,000 1,350 2,000	Cat. Poly.	
Moose Jaw	Canadian Husky Oil Ltd.	S.A.	1949	Southwest Saskatchewan	3,000			Cat.Reforming Dieselforming	

Location of Refinery	Company	Type of Refinery	Date of First Operation	Source of Crude	Crude Oil Capacity B/CD	Cracking Plant Units	Cracking Capacity B/CD	Other Units	Proposed for 1958.
Regina	Consumers' Co-operative Refineries Ltd.	Comp.	1935	Alberta Saskatchewan	15,000	Catalytic - fluid Thermal - visbreaking	5,000 3,000	Vac.distillation Cat.Poly.	Low pressure coking unit, capacity 3000 BSD Feed, 145 tons/day Coke.
Regina	Imperial Oil Ltd.	S.C.A.	1916	Alberta	22,500	Catalytic - fluid Thermal - cracking	8,500 4,500	Cat.Reforming Cat. Poly.	
Kamsack	Northern Petroleum Corp.Ltd.	S.	1936	Wapella, Sask.	1,000				
Moose Jaw	Petroleum Fuels Ltd.	S.	1953	Saskatchewan	1,100				
Prince Albert	Prince Albert Refineries Ltd.	S.A.	1950	Coleville, Sask.	1,000				
Saskatoon	Royalite Hi-Way Ltd.	S.C.A.	1933	Alberta and Saskatchewan	6,500	Catalytic - fluid	2,600	Cat.Poly.	
Coleville	Royalite Oil Company Ltd.	S.A.	1953	Coleville, Sask.	5,000			Oxidizing Unit	
ALBERTA									
Hartell	Anglo American Exploration Ltd.	S.C.A.	1939	Turner Valley, Alberta.	4,000	Thermal - cracking	1,350	Cat.Poly. Cat.Reformer	
Bonnyville	Bonnyville Oil Refineries Ltd.	S.	1952	Bonnyville, Alberta.	1,000				

Location of Refinery	Company	Type of Refinery	Date of First Operation	Source of Crude	Crude Oil Capacity B/CD	Cracking Plant Units	Cracking Capacity B/CD	Other Units	Proposed for 1958
Calgary	The British American Oil Co.Ltd.	S.C.A.	1939	Alberta	6,800	Thermal - cracking	2,250	Cat.Reformer	
Edmonton	The British American Oil Co.Ltd.	S.C.	1951	Alberta	7,800	Catalytic - fluid Thermal - cracking - delayed coking	1,800 1,300 1,900	Cat. Reformer	
Lloydminster	Canadian Husky Oil Ltd.	S.A.	1947	Alberta and Saskatchewan	8,500			Cat. Reformer, Desulphurization	
Lloydminster	Excelsior Refineries Limited	S.A.	1945	Alberta and Saskatchewan	4,000			2 Asphalt Oxidizers	
Calgary	Imperial Oil Ltd.	S.C.A.	1923	Alberta	6,750	Thermal - cracking	4,600	Alkylation Unit	Increase crude capacity to 14,700 B/CD; Powerforming 2700; catalytic cracking 6600.
Edmonton	Imperial Oil Ltd.	S.C.	1948	Alberta	28,500	Catalytic - fluid Thermal - cracking	8,500 6,000	Powerformer Lube Plant	
Edmonton	McColl-Frontenac Oil Co. Ltd.	S.C.	1951	Alberta	11,900	Catalytic - fluid Thermal - cracking	4,070 2,700	Cat. Poly. Cat. Reformer	
Grande Prairie	North Star Oil Limited	S.C.	1956	Alberta	2,500	Thermal - cracking	1,000	Cat.Reformer Cat.Desulph.	

Location of Refinery	Company	Type of Refinery	Date of First Operation	Source of Crude	Crude Oil Capacity B/CD	Cracking Plant Units	Cracking Capacity B/CD	Other Units	Proposed for 1958
Wainwright	Wainwright Producers & Refiners Ltd.	S.A.	1934	Alberta	3,500			Vac.distillation	3000 b/d thermal cracker & 1000 b/d cat. reformer & desulphurizer. Crude throughput increased to 4000 b/d.
BRITISH COLUMBIA									
Ioco	Imperial Oil Ltd.	S.C.A.	1915	Alberta	30,000	Catalytic - fluid	7,650	Cat.Poly.	Powerformer comp.early 1958.
Kamloops	Royalite Oil Company Ltd.	S.C.A.	1954	Alberta	5,000	Catalytic - fluid	1,400	Cat. Poly.	Completion of 1000 b/d platformer; plan 1500 b/d unifiner.
Burnaby	Shell Oil Company of Canada Ltd.	Comp.	1932	Alberta	19,500	Catalytic - fluid Thermal - visbreaking	5,700 4,000	Cat.Poly. Platformer Vac.Flashing	Additional facilities for manufacture of special solvents for dry cleaning and paint & varnish industries.
North Burnaby	Standard Oil Co.of British Columbia Ltd.	Comp.	1936	Alberta	18,000	Catalytic - fluid	9,000	Cat.Poly. Cat. Reformer	Lube oil blending plant.

Location of Refinery	Company	Type of Refinery	Date of First Operation	Source of Crude	Crude Oil Capacity B/CD	Cracking Plant Units	Cracking Capacity B/CD	Other Units	Proposed for 1958
Dawson Creek	X-L Refineries Limited	S.C.	1955	Northern Alberta and British Columbia	3,000	Thermal - cracking	740	Cat.Reformer Houdriformer	Possible installation of facilities for manufacture of asphalt.
NORTHWEST TERRITORIES									
Norman Wells	Imperial Oil Ltd.	S.	1921	Norman Wells	1,300				

DAILY* CRUDE OIL CAPACITY OF CANADIAN PETROLEUM REFINERIES

	1937		1947		1948		1949		1950		1951		1952		1953		1954		1955		1956		1957	
Province	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D	No.	B/D
Nova Scotia	1	11,000	1	34,000	1	25,000	1	22,000	1	22,000	1	22,000	1	22,000	1	18,000	1	18,000	1	18,000	1	42,000	1	44,500
New Brunswick	1	300	1	300	1	300	1	300	1	300	1	300	1	300	1	300	1	300	1	300	1	300	1	300
Quebec	5	68,500	4	73,000	4	107,000	4	124,000	4	143,000	4	160,000	4	164,000	4	176,000	4	171,500	5	210,000	5	247,000	5	255,800
Ontario	5	40,500	6	87,950	6	88,700	5	83,700	4	75,200	4	79,400	5	104,500	6	135,000	6	142,300	6	148,800	6	159,700	6	201,600
Manitoba	3	2,450	3	4,500	3	4,500	3	7,300	3	7,800	4	20,500	4	19,700	4	20,000	4	20,000	4	29,800	4	30,800	4	35,000
Saskatchewan	18	16,570	7	17,475	7	26,475	7	26,475	8	33,575	10	47,500	8	50,300	10	58,100	10	67,300	9	66,300	9	69,350	9	68,600
Alberta	8	9,800	6	21,300	7	35,750	7	43,200	7	46,900	11	61,750	12	68,000	10	69,150	10	68,600	10	77,500	11	79,350	11	85,250
British Columbia	3	19,500	3	22,300	3	26,650	3	25,650	3	28,850	3	28,850	3	28,350	3	45,850	4	55,500	5	66,500	5	70,250	5	75,500
N.W.T.	1	150	1	1,100	1	1,100	1	1,000	1	1,250	1	1,250	1	1,250	1	1,250	1	1,250	1	1,250	1	1,300	1	1,300
CANADA TOTAL	45	168,770	32	261,925	33	315,475	32	333,625	32	358,875	39	421,550	39	458,400	40	523,650	41	544,750	42	618,450	43	700,050	43	767,850

* - Calendar Day

ESTIMATE OF WESTERN CANADIAN CRUDE OIL DISPOSITION - 1957 (1)

Source	Destination:	British Columbia	Prairie Provinces	Ontario	Northwest Territories	U.S.A. Puget Sound	U.S.A. South (2)	U.S.A. Great Lakes Area	Vancouver Marine Terminal (3)	TOTAL
B. C.	1st Quarter	103,997	-	-	-	-	-	-	-	103,997
	2nd Quarter	78,754	-	-	-	-	-	-	-	78,754
	3rd Quarter	80,549	-	-	-	-	-	-	-	80,549
	4th Quarter	89,742	-	-	-	-	-	-	-	89,742
	Total	353,042	-	-	-	-	-	-	-	353,042
Alberta	1st Quarter	6,678,301	10,910,734	8,371,552	-	6,861,365	16,039	1,902,428	3,216,887	37,957,306
	2nd Quarter	6,191,469	10,368,710	9,668,852	-	6,636,377	20,658	1,564,462	3,595,745	38,046,273
	3rd Quarter	6,242,758	12,095,131	8,212,486	-	7,806,550	23,005	1,334,772	328,369	36,043,071
	4th Quarter	3,267,117	9,689,293	8,057,668	-	5,633,251	16,404	1,438,328	-	28,102,061
	Total	22,379,645	43,063,868	34,310,558	-	26,937,543	76,106	6,239,990	7,141,001	140,148,711
Saskatchewan	1st Quarter	-	3,250,878	1,905,469	-	-	-	2,748,273	-	7,904,620
	2nd Quarter	-	2,445,202	2,895,744	-	-	-	3,003,858	-	8,344,804
	3rd Quarter	-	2,327,693	4,556,897	-	-	-	2,784,835	-	9,669,425
	4th Quarter	-	2,870,567	4,359,010	-	-	-	3,402,154	-	10,631,731
	Total	-	10,894,340	13,717,120	-	-	-	11,939,120	-	36,550,580
Manitoba	1st Quarter	-	268,037	149,733	-	-	-	1,013,728	-	1,431,498
	2nd Quarter	-	-	534,116	-	-	-	804,887	-	1,339,003
	3rd Quarter	-	52,482	972,732	-	-	-	646,531	-	1,671,745
	4th Quarter	-	18,279	902,758	-	-	-	666,532	-	1,587,569
	Total	-	338,798	2,559,339	-	-	-	3,131,678	-	6,029,815
N. W. T.	1st Quarter	-	-	-	130,193	-	-	-	-	130,193
	2nd Quarter	-	-	-	84,701	-	-	-	-	84,701
	3rd Quarter	-	-	-	123,354	-	-	-	-	123,354
	4th Quarter	-	-	-	44,453	-	-	-	-	44,453
	Total	-	-	-	382,701	-	-	-	-	382,701
TOTAL WESTERN CANADIAN DISPOSITION		22,732,687	54,297,006	50,587,017	382,701	26,937,543	76,106	21,310,788	7,141,001	183,464,849

1) Disposition differs from actual production due to inventory and loss.
2) Crude oil exported from southern Alberta to northern Montana.
3) Offshore shipments.

CANADIAN PETROLEUM ASSOCIATION'S

RESERVES COMMITTEE

RULES FOR CALCULATING PROVED RESERVES

The following is the set of rules for calculating proved reserves used by the members of the Canadian Petroleum Association's (C.P.A.) Reserves Committee. In general, the principles established by the American Petroleum Institute's (A.P.I.) and American Gas Association's (A.G.A.) Reserves Committees will be followed, except in a few instances where the C.P.A. Committee feels that it is in order to deviate from these principles. It should be emphasized that these rules are not hidebound and, in many instances, it will be necessary for the engineer to use his best judgment as to whether or not certain reserves should be included as proved. As a general principle, it is better to be conservative and make upward revisions the following year after additional data is obtained than to find it necessary to make downward revisions at that time.

OIL AND NATURAL GAS LIQUID RESERVES

The estimates refer solely to proved or blocked-out reserves. They include only oil and natural gas liquids recoverable under existing economic and operating conditions. These estimates should not include:

(1) Oil under the unproved portions of partly developed fields.

(2) Oil in untested prospects.

(3) Oil that may be present in unknown prospects in regions believed to be generally favorable.

(4) Oil that may become available by fluid injection methods from fields where such methods have not yet been applied.

(5) Oil that may become available through chemical processing of natural gas.

(6) Oil that can be made from oil shale, coal, or other substitute sources.

OIL RESERVES

Wells or Areas to be Included

Proved reserves are both drilled and undrilled. Proved drilled reserves in any pool should include the oil estimated to be recoverable by the production systems now in operation, whether with or without fluid injection, and from the area actually drilled up on the spacing pattern in vogue in that pool. The proved undrilled reserves in any pool should include reserves under undrilled spacing units which are so related to the drilled units that there is every reasonable probability that they will produce when drilled.

N.B. As a general rule, in partially developed fields only immediate and diagonal offsets to drilled wells are included. However, where the geological information is such that there is every reasonable probability that undrilled spacing units will produce when drilled, such spacing units should be included in the proved reserves. If for any reason any of these offset locations are questionable, then they should be excluded. Where sufficient information is available to warrant taking in a larger area, then the larger area will be used.

In the case of new discoveries, both of new fields and new pools (pays, reservoirs) in old fields which are seldom fully developed in the first year and, in fact, for several years thereafter, the estimates of proved reserves necessarily represent only a part of the reserves which may ultimately be assigned to the new reservoirs discovered each year. For a one-well field where development has not yet gone beyond the discovery well, the area assigned as proved is usually small in regions of complex geological conditions, but may be larger where the geology is relatively simple. In a sparsely drilled pool the area between wells is considered to be proved only if the geological and engineering data assure that such area will produce when drilled. The total of new oil through discoveries estimated as proved in each year is comparatively small because the development is usually not extensive during the first year. The total of new oil through extensions, on the other hand, is comparatively large. As knowledge of the factors affecting production and reservoir performance becomes available, and as these factors are studied, reserves in the older fields can be estimated with greater precision and revised accordingly. Therefore, the total quantity of the new proved reserves for the year should include the oil from discoveries and extensions modified by revisions of previous estimates where new data have made better information available.

N.B. In the case of new discoveries, both of new fields and of new pools in old fields in which there is only one well drilled at the time of making the estimate, it is usual practice for the C.P.A. to use only one spacing unit for reserve calculations. Where sufficient information is available to warrant taking in a larger area, then the larger area will be used.

Fields or Pools on Which Only Drill Stem Tests Have Been Run

The A.P.I. Committee do not include reserves from pools which have been cased through and left unperforated, or a zone which has only been production tested by a drill stem test, unless at least one well in such pool has been produced for a sufficient time to establish the fact that commercial production can be obtained. The C.P.A. Committee feel that in certain instances where results of the drill stem tests leave no doubt that commercial production can be obtained that such reserves should be included.

Uneconomic Pools or Fields

In the case of a pool in which wells have been drilled, cased and proven uncommercial after a production test, the reserves should be excluded.

Oil reserves in pools or fields where it is uneconomical to produce same as a result of quality of oil and operating costs under the present economic

conditions should not be included. However, fields which are not now economical to produce due to the lack of pipe line facilities, but which would be economical if the pipe line facilities were installed (and it is probable that such facilities will be installed at a future date) should be included in the proved reserves.

Fluid Injection

The term "fluid injection" includes:

(1) What is commonly called "pressure maintenance".

(2) Cycling.

(3) Secondary recovery in its original sense, namely, fluid injection applied relatively late in the development history of a reservoir (pool) with the purpose of stimulating petroleum production after recovery by primary methods of flowing and pumping has approached an economic limit.

The reserves which may become available as a result of fluid injection are regarded as proved only after thorough testing by a pilot plant or, better, after operation of an installed fluid injection procedure has actually demonstrated certainty of recovery. Then, and only then, should such reserves be included in estimates of proved reserves.

NATURAL GAS (14.65 psia at 60°F)

Wells or Area to be Included

A proved reserve may be in either a drilled or undrilled portion of a given field. When the undrilled area is considered proved, it is so related to the developed acreage and the known field geology and structure that its productive ability is considered assured.

The A.G.A. follow a similar practice to that used by the A.P.I. Committee with regard to the area included for oil reserves. It is common practice to include only one spacing unit for a new discovery in a new field or in a new pool in an old field.

N.B. If any shut-in gas well is excluded by the area representative in calculating reserves, or if the area representative has included any shut-in gas well that he is in doubt about, the matter should be brought to the attention of the Committees.

Abandonment Pressures

The A.G.A. make a practice of including as proved recoverable reserves of natural gas, those reserves estimated to be producible under present operating practices. Since the estimates are made by pools, recovery or abandonment pressures used in the calculations are governed by the operating

conditions in each individual pool.

If the gathering pressures used initially in a pool are used for calculating reserves, such estimates could very well be ultra-conservative. Probably the best solution would be to have the engineer making the reserve study use an abandonment pressure based on the economics of producing, on the conservative side.

Shrinkage

Proved gas reserves are based on the estimated recoverable gas in the state it occurs in the formation, less any shrinkage that is anticipated, if the gas is to be processed, for natural gas liquids, hydrogen sulphide, carbon dioxide, etc., but no adjustment is made for gas which it is estimated will be flared, used in the field or in processing plants, etc. This latter gas is shown as production at the time it is actually withdrawn, and reserves reduced at that time.

Classification of Natural Gas

In making estimates of proved recoverable reserves of natural gas, a breakdown should be made to show the amount of non-associated, associated, dissolved and underground storage.

Non-associated gas is free gas not in contact with crude oil in the reservoirs.

Associated gas is free gas in contact with crude oil in the reservoirs.

Dissolved gas is gas in solution with crude oil in the reservoirs.

Underground storage is net gas placed in underground reservoirs for storage purposes only.

Underground Storage

Stored gas reserve is the quantity placed in a natural gas reservoir and not yet removed. This includes only gas which is transferred from one field to another natural underground reservoir in another field, not to another area in the same pool from which it is withdrawn or to another pool in the same field.

The A.G.A. have made a change with regard to stored gas. In previous years, stored gas was considered to be that gas which had been transferred from its original reservoir location in a gas or oil field to another underground reservoir for the primary purpose of conservation, fuller utilization of pipe line facilities, and more efficient delivery to markets. Any additional gas remaining in the underground storage reservoir when injection began, and which had not been produced, was classified and listed, for the most part, as a non-associated natural gas. Beginning in 1953, the A.G.A. Committee has included in the underground storage figure that gas "cushion gas" which

was native to the reservoir at the time storage injection began. Correspondingly, this "cushion gas" has been subtracted from its previous reserve category. Adjustments in, withdrawals from, or additions to storage are included in the figures shown under the heading "Net Change in Underground Storage". This is distinguished from the net production which is gross withdrawals less gas injected into producing reservoirs. Changes in underground storage are excluded from net production.

Pressure Maintenance

Any gas that is re-injected for pressure maintenance purposes shall be treated as negative production.

Marginal or Uneconomic Fields

Following the discussion in Banff, it is felt that remoteness from any existing or proposed gas transmission line should not be a factor in excluding gas reserves. It is felt that the only gas reserves which should be excluded are those which it would be uneconomical to gather in the event a transmission line was laid within a short distance of such reserves.

NATURAL GAS LIQUIDS

The A.P.I. and A.G.A. Committees define proved recoverable reserves of natural gas liquids as those contained in the recoverable gas reserves subject to being produced as natural gas liquids by separators or extraction plants now in operation, under construction, or planned for the immediate future. (See next paragraph for recommended practice by C.P.A.) For purposes of developing reserve estimates, natural gas liquids are defined as those hydrocarbon liquids which are gaseous, either free or in solution with crude oil in the reservoir, and which are recoverable as liquids by the processes of condensation or absorption which take place in field separators, scrubbers, gasoline plants, or cycling plants. Natural gasoline, condensate and liquified petroleum gases fall in this category. While the liquids so collected and the products derived from them in some of the modern plants are known by a variety of names, they should be grouped together under the general heading "Natural Gas Liquids".

Natural Gasoline and Liquified Petroleum Gases.

No reserve for natural gas liquids should be set up for a field which is allowed to flare the gas produced with crude oil until such time as a gasoline plant is actually in operation. For reservoirs or portions of reservoirs where it is known that no production of natural gas will be allowed, except the natural gas produced in association with crude oil, until a gasoline plant is installed, and it is evident that it will be economical to install such a plant, natural gas liquid reserves should be set up. This would apply to wet gas reservoirs, e.g., Pincher Creek, and gas caps in association with

crude oil, e.g., Homeglen-Rimbey. In the Homeglen-Rimbey field reserves should not be set up for the natural gas liquids in the gas produced with crude oil until such time as a gasoline plant is placed in operation. However, a natural gas liquid reserve should be set up for the gas cap in this field as the Conservation Board would not allow production from the gas cap without a gasoline plant. For such fields, the A.G.A.'s practice is to assigne a token figure of from 5 to 10 barrels per MMcf(.175 to .35 GPM). This figure is revised when the plant actually goes into operation. In making our estimates it is felt best to use recoveries based on gas analyses where available, using a conservative recovery figure for the L.P.G. products.

Condensate

In calculating condensate production, the A.G.A. Committee include any condensate recovered in a separator and mixed with crude oil as crude oil production. If the condensate is not mixed with crude oil, it is reported as a natural gas liquid. The main consideration in this matter is that condensate production must not be duplicated, i.e., included with crude oil production and also with the natural gas liquids. In calculating condensate reserves, it is the A.G.A.'s practice to include the reserve of condensate in a gas cap as a natural gas liquid reserve. If a portion of this reserve is produced with crude oil, then it is shown as crude oil production. The portion of the production which is estimated to be condensate is deducted from the condensate reserve. Similarly, only the portion of the production which is estimated to come from the oil zone is deducted from the crude oil reserve of the pool from which it is produced.

NATURAL GAS PROCESSING PLANTS

Company	Location of Plant	Raw Material and Source	Date of First Operation	Capacity MMCFGPD '47	'50	'51	'52	'53	'54	'55	'56	'57	Principal Products	Remarks
ALBERTA														
Anglo American	Hartell	Raw Gas and Naphtha from Turner Valley Field	1934	10	10	10	10	10	10	10	10	10	Natural Gasoline, Isobutane	Absorption type plant. Residue gas to Canadian Western
British American	Longview	Raw gas from Turner Valley field	1936	20	20	20	15	15	10	10	10	7	Natural gasoline	Absorption type plant. Residue to Canadian Western
	Nevis	Solution gas from Stettler, Fenn-Big Valley and Erskine fields.	1956	-	-	-	-	-	-	-	20	12	Natural gasoline, propane, butane.	Refrigeration type plant. Residue gas to Canadian Western
	Pincher Creek	Raw gas from Pincher Creek field	1957	-	-	-	-	-	-	-	-	60	Condensate, Sulphur	Absorption type plant. Ultimate capacity 240 MMCFGPD Residue gas to Trans-Canada.
Imperial Oil	Devon	Solution gas from Leduc-Woodbend field	1950	-	24	24	24	24	24	24	24	25	Natural gasoline, LPG's.	Refrigeration type plant. Residue gas to Northwestern Utilities.

Company	Location of Plant	Raw Material and Source	Date of First Operation	Capacity MMCFGPD '47	'50	'51	'52	'53	'54	'55	'56	'57	Principal Products	Remarks
Imperial	Redwater	Solution gas from Redwater field	1956	-	-	-	-	-	-	-	9.5	9.5	Natural gasoline LPG's, Sulphur	Refrigeration type plant. Residue gas to local market.
Progas Limited	Winterburn	Solution gas from Acheson field	1954	-	-	-	-	-	5	5	5	5	Natural gasoline, LPG's.	Absorption type plant. Residue gas to Northwestern Utilities.
	Big Valley	Solution gas from Fenn-Big Valley field	1954	-	-	-	-	-	2	2	2	-	Natural gasoline, LPG's	Absorption type plant. Operations suspended since 3-12-56. Plant partly dismantled. Moving to another location.
Provo Gas Producers	Consort	Raw gas from Viking gas wells in Provost field	1957	-	—	-	-	-	-	-	-	45	Condensate	Refrigeration type plant. Residue gas to Trans-Canada.
Royalite	Turner Valley	Raw gas and solution gas from Turner Valley field	1933	100	100	100	100	100	100	100	100	100	Natural gasoline, propane, sulphur.	Absorption type plant. Residue gas to Canadian Western.
Shell Oil	Cochrane	Raw gas from Jumping Pound field	1951	-	-	35	35	35	60	60	60	90	Natural gasoline, condensate, sulphur	Combination absorption refrigeration plant. Residue gas to Canadian Western.

Company	Location of Plant	Raw Material and Source	Date of First Operation	Capacity MMCFGPD '47	'50	'51	'52	'53	'54	'55	'56	'57	Principal Products	Remarks
Texaco	Pigeon Lake	Solution gas from Bonnie Glen, Wizard Lake, and Glen Park fields.	1954	-	-	-	-	-	20	20	20	35	Propane, butane, natural gasoline.	Absorption type plant. Residue gas to Northwestern Utilities.
BRITISH COLUMBIA														
McMahon Plant	Taylor Flats	Raw gas from S.E. Fort St. John, Montney, Stoddard & Portland areas.	1957	-	-	-	-	-	-	-	-	300	Alkylate, sulphur, LPG's. Natural gasoline	The preliminary design of the gas scrubbing plant estimates raw liquid production at 3500 BPD. Residue gas to Westcoast Transmission, sulphur to Jefferson Lake Sulphur Co.
SASKATCHEWAN														
Imperial Oil	Smiley	Solution gas from Coleville-Smiley field	1957	-	-	-	-	-	-	-	-	3	Natural gasoline	Refrigeration type plant. Residue gas to Saskatchewan Power.